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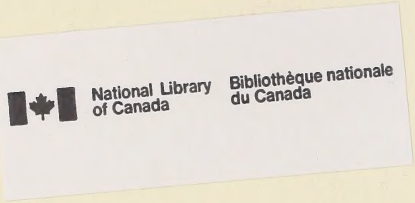
Risk Approach

An Approach for Estimating Risk to Public Safety from Uncontrolled Sour Gas Releases

October 1990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AN APPROACH FOR ESTIMATING RISK TO PUBLIC SAFETY FROM UNCONTROLLED SOUR GAS RELEASES

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OCTOBER 1990

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1 BACKGROUND

Implicit in the operation of sour gas facilities is the possibility of an accidental release of sour gas to the atmosphere. For example, during the 14-year period 1975 to 1988, five well blowouts occurred during the drilling of sour wells, seven blowouts occurred during sour gas production and seven occurred during non-production phases of operation. During the 14-year period 1975 to 1988, at least 30 ruptures were associated with sour gas pipelines. Due to the toxicity of H_2S, a large uncontrolled release upwind and close to a populated area could have serious consequences.

In the previous phase of this study, GASCON2, a **hazard** and **consequence assessment** model for uncontrolled sour gas releases, was developed. A hazard assessment is concerned with determining the consequences of an accidental release of sour gas.

Since a hazard assessment does not consider the causes of accidental events, it can not give a measure of how likely an accident is. If a hazard assessment is to be at all useful to emergency planners, it must give the hazards due to **worst case** scenarios, that is, accidental releases that give the largest ground level toxic gas concentrations, or the largest hazard zones. The trouble with worst case scenarios is that it is difficult to make planning decisions based on them alone. If people adopted worst cases as the basis for all of their decision-making, no action would ever be taken for fear of the possible outcomes. Almost any activity that would come to mind would be fraught with possible (but unlikely) consequences.

It is important to recognize that a worst case hazard alone cannot give a good measure of danger to the public; it must be viewed in terms of the likelihood of such a worst-case hazard occurring. When one speaks of the **likelihood**, or the **chances**, or the **probability** of an adverse consequence occurring, one is really referring to a concept called **risk**. Simply defined, risk is the likelihood that an adverse consequence will occur due to accidental events.

2 PROJECT OBJECTIVES

The overall objective of this project is the development of a simplified approach for estimating the risk to the public from potential uncontrolled sour gas releases. Risk depends on the consequence and frequency of events. The consequences of uncontrolled sour gas releases are estimated using GASCON2 (Alp *et al.* 1990). This report documents the approach to obtain the frequencies and provides the historical frequency of uncontrolled sour gas releases in Alberta.

More specifically, the objective of this phase of the study is to develop a risk assessment method, consisting of a frequency analysis approach and a computer-based consequence assessment model, which can be used as a practical tool for estimating the risk to the public posed by accidental sour gas releases. The steps were:

- To review the literature to establish what is the current knowledge on frequency analysis applied to uncontrolled sour gas releases,
- To evaluate historical data to determine the frequency of uncontrolled sour gas releases,

- To incorporate these results, along with the GASCON2 hazard and consequence assessment model, into a risk assessment approach, and

- To apply the approach to the various generic worst-case conditions.

The project described in the report was done under contract to the Energy Resources Conservation Board (ERCB) by Concord Environmental Corporation. A Scientific Advisory Board appointed by the ERCB provided peer review to assure the technical acceptability of the overall approach.

3 RISK ASSESSMENT METHOD

Risk is an inseparable part of everyone's life. Every person lives with the knowledge that an unexpected event can intervene at any time in their life, and that some events are more likely to happen (i.e. riskier) than others. The less risk posed to us by accidental events, the safer we are. Therefore, risk, which is a quantifiable number (e.g. 1 chance in a million, or a probability of 0.000001), is an objective measure of how safe people are from accidental events.

Consideration of risk is preferable to worst case scenarios for emergency planning purposes. With a risk assessment, it is possible to examine various safety measures and see how significantly they reduce the risk. This is often termed "**looking at mitigative measures**". When risk numbers, along with costs, benefits and mitigating measures enter into the decision-making of emergency planners, the process is often called **risk management**.

The relationship between hazard assessment and risk assessment is shown schematically in Figure 1. Risk assessments are divided into two main parts: the **frequency analysis** and the **consequence analysis**. The main component of the consequence analysis is the detrimental effects modelling, which estimates the adverse effects of the toxic gas concentrations given by the hazard assessment. The frequency analysis part of the risk assessment deals with estimating how likely an accidental release of sour gas is. The main component of frequency analysis is a tool called **fault tree analysis**, which is the development of a diagram showing the chain of sub-events that must occur for an accidental release of sour gas to happen.

In this study, an accidental sour gas release is termed an **uncontrolled sour gas release event**, or simply **event**, for short.

Consequence analysis answers four questions for a given event:

- *What is the concentration of H_2S at locations downwind of a release point?*

- *How large is the hazard zone where H_2S concentrations exceed a criteria level?*

- *What is the probability of receiving a lethal toxic load (dose) of H_2S at locations downwind of a release point?*

- *How many potential fatalities could occur if there were people outdoors during the release?*

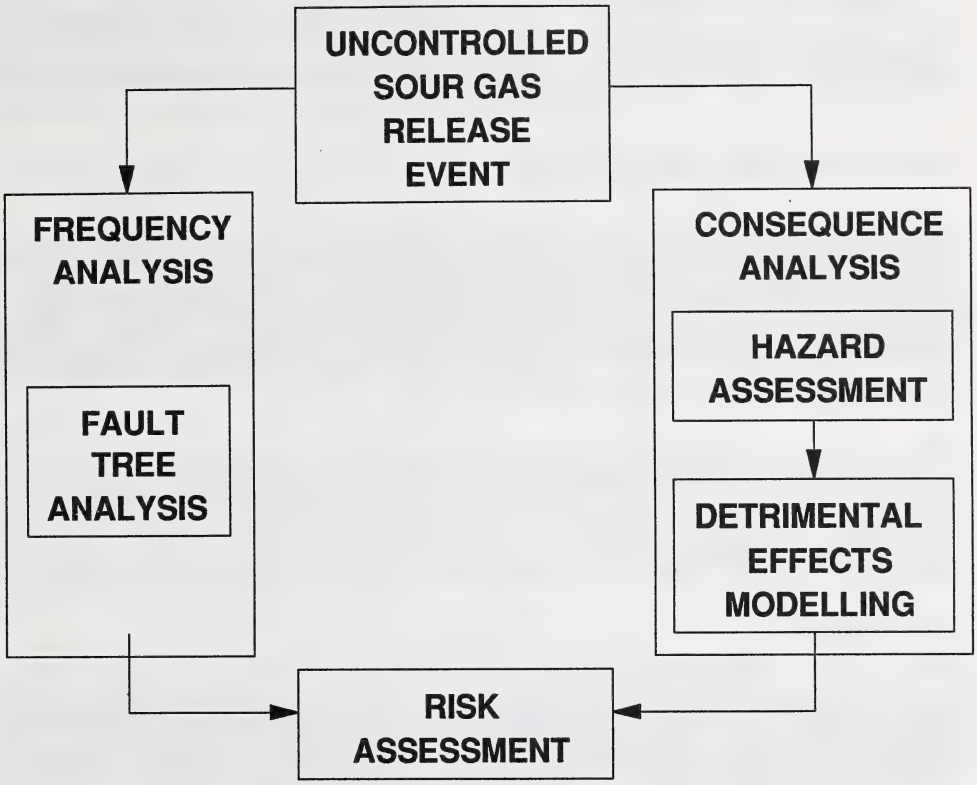


Figure 1

General Risk Assessment Elements.

The frequency analysis answers the questions:

"What are the chances of an event occurring?"

Mathematically speaking, risk is the frequency of an event times the consequence of an event.

Two kinds of risk numbers come out of the risk assessment: individual risk and societal risk. In this study, **individual risk** is taken to mean the frequency that a person will receive a lethal exposure of H_2S due to an accidental release. This likelihood will change from one downwind location to another, and from one kind of accidental release to another. **Societal risk** is an estimate of the frequency of fatalities which could result from an accidental sour gas release. This may be viewed as the sum of the individual risks of all the people in the area to the sour gas release. Again, the societal risk will change from one kind of accidental release to another.

The approach described in this report determines **incident risk** for a given uncontrolled sour gas release event. **Facility risk** is the sum of the incident risks for all of the possible uncontrolled sour gas release events. In practice, worst case events are selected to represent the possible events.

4 CONSEQUENCES ANALYSIS

An event is defined by a unique combination of sour gas **release conditions** and **weather conditions**. The event results in ground level toxic gas concentrations which vary with distance from the release point and, hence, also results in varying potential for fatal exposures to toxic gas. There are a number of factors which define the release conditions and weather conditions, and hence an event. In addition to these, **detrimental effects factors** are also required to estimate the consequences of an event.

These release and weather conditions that define an event and the detrimental effects factors, which are inputs to the GASCON2 model, will now be described in some detail.

4.1 Release Conditions

Well Blowouts

A well blowout is characterized by a continuous release rate of sour gas until the well is brought under control. The duration of the release can typically be days or even weeks, although ignition of the sour gas can take place in a matter of minutes or hours. The rate at which sour gas escapes from the well (called the release rate) is either known for producing wells, or can be estimated from the release rates of nearby wells in the same geological formation for proposed wells. Figure 2 shows the types of uncontrolled well flows considered.

Pipeline Ruptures

In contrast to well blowouts, pipeline ruptures typically last in the order of minutes rather than hours or days. At the moment of rupture, the flow rate of escaping gas is high. Since the ruptured section of pipeline is isolated by Emergency Shutdown Valves (ESD) from the wells and the rest of the pipeline system, the line pressure and flow rate decrease as the isolated section of pipeline is depleted of sour gas. The model is capable of predicting the flow rate of sour gas through a pipeline rupture opening, given the following:

- Area of the rupture opening.
- Internal diameter of the pipeline.
- Length of pipeline which is being depleted.
- Line pressure in the pipeline before rupture.
- Line temperature in the pipeline before rupture.

- Sour gas composition.

The above factors are known from pipeline operating conditions or can be estimated. Figure 3 shows the kind of pipeline ruptures that have been considered.

Flow Orientation

Should a well blowout or pipeline rupture occur, the escaping gas would not necessarily be an upward directed jet of sour gas. A pipeline rupture can occur anywhere along the circumference of the pipeline. The flow from a well blowout can be re-directed or slowed down by obstacles to the flow, or can be directed horizontally by valve fittings. Figures 4 and 5 show the flow orientation considered for both well blowouts and pipeline ruptures.

Gas Composition

The amount of hydrogen sulphide (H_2S) in the sour gas is important in determining what the H_2S concentration would be downwind of an accidental release. This can vary considerably from one gas pool to another. The constituents of sour gas are either known for producing wells or can be estimated from nearby wells in the same pool for proposed wells.

All the constituents of the sour gas (for example, methane, hydrogen sulphide, propane, ethane, carbon dioxide, nitrogen, etc.) are important in estimating the properties of sour gas and in estimating what happens when the gas is ignited. Perhaps the most important property of sour gas to be determined is its **density**, which normally is somewhat less than that of air, and which affects the buoyant rise of the sour gas plume in the atmosphere.

Ignited or Unignited

The ignition of a sour gas release can be either by design or by accident. For ignited releases, the toxic material of concern is sulphide dioxide (SO_2), whereas for unignited releases, the toxic material of concern is hydrogen sulphide (H_2S). Ignition causes a significant rise in the temperature of the released material, making it rise further in the atmosphere. Consequence analysis is only done for unignited releases because H_2S concentrations are higher and H_2S is more toxic.

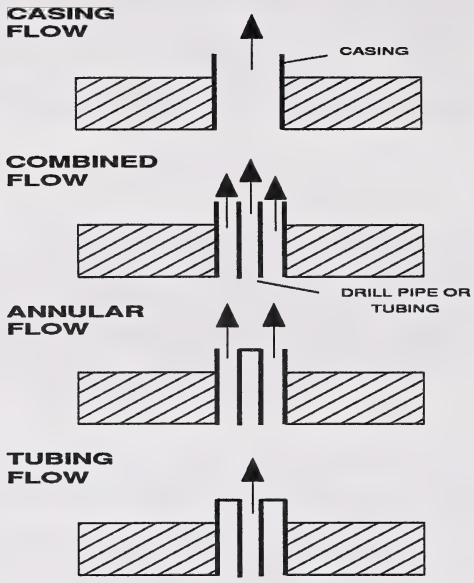


Figure 2

Possible Well Flow Scenarios.

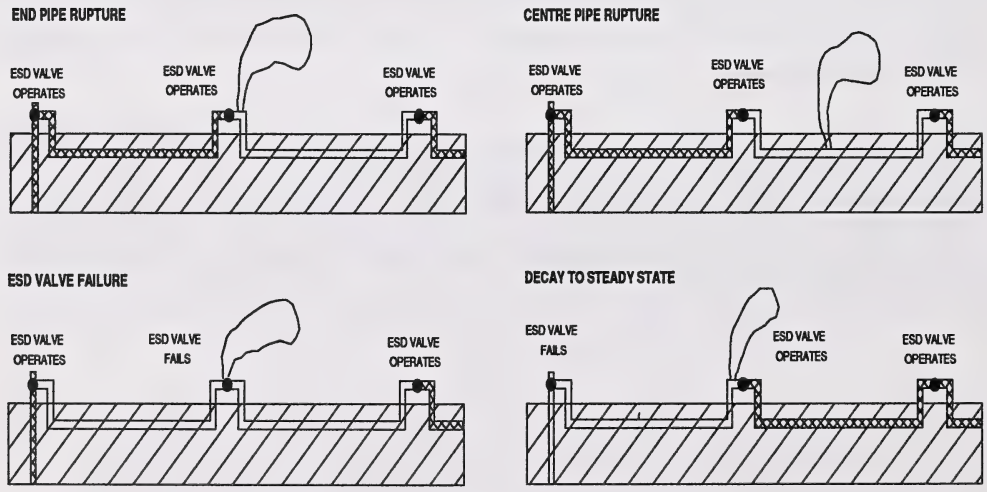


Figure 3

Possible Pipeline Rupture Scenarios.

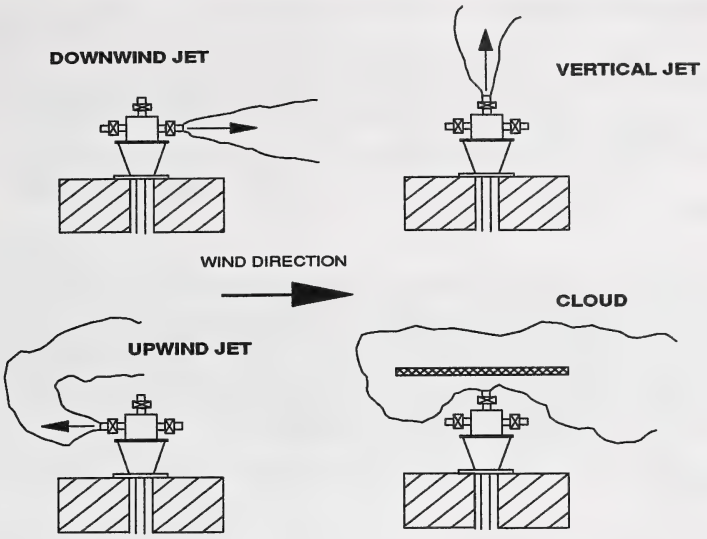


Figure 4

Possible Well Release Geometries.

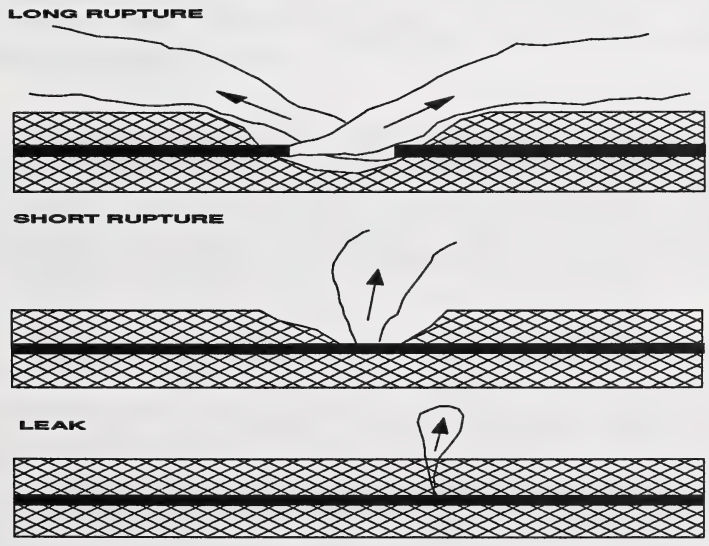


Figure 5

Possible Pipeline Release Geometries.

4.2 Weather Conditions

Weather conditions determine the ability of the atmosphere to transport and dilute the sour gas from an accidental release. The following are the weather factors that determine the dispersing capability of the atmosphere.

Wind Speed

Wind speed directly affects the transport of toxic gases in the atmosphere by determining the distance the material moves in a given period of time and the dilution of the material in the along-wind direction. Indirectly, wind speed also affects the rise of the sour gas plume (the faster the wind speed, the lower the plume rise) and the level of turbulence in the atmosphere (the faster the wind speed, the greater the level of turbulence). Increased turbulence levels will increase the dilution of the plume.

Wind Direction

Wind direction determines the direction in which sour gas will be carried and dispersed and the geographical area which will be exposed to the toxic gas.

Temperature

At colder outdoor temperatures, the ambient air becomes more dense relative to the sour gas. Because the sour gas is more buoyant in these situations, it will tend to rise higher. The converse is true for warmer temperatures.

Surface Roughness

Surface roughness is a site-dependent factor which depends on the presence of terrain features such as trees, buildings and crops. An increase in surface roughness will increase the dilution of toxic gas releases. Surface roughness factors are tabulated in many meteorological reference texts under qualitative descriptions of various terrain types.

Stability

Atmospheric stability refers to the level of turbulence in the lowest level of the atmosphere, known as the Planetary Boundary Layer (PBL), within which we live.

- **Unstable** conditions occur when there is significant solar heating of the ground, as one might expect during sunny daytime hours in summer. Under these conditions, large scale convective motions in the form of updrafts and downdrafts are set up in the PBL, causing the rapid dilution of toxic material.

- **Stable** conditions occur when there is cooling of the ground by radiation, as one might expect during the night. Turbulent motions are suppressed in the PBL and toxic gas disperses slowly in these conditions.

- **Neutral** conditions occur when turbulence is neither enhanced (as in unstable conditions) nor suppressed (as in stable conditions). Neutral conditions can occur during transition periods between stable and unstable and vice versa. They can also occur under high wind conditions.

Atmospheric stability is not a routinely measured parameter, and must be inferred from other routine weather observations.

Mixed Layer Height

This is essentially the height of the PBL in which turbulent mixing takes place. Due to strongly suppressed levels of turbulence at the top of the mixed layer and possible temperature inversions, the mixed layer height can often act as a lid, restricting vertical movement of sour gas plume. This can reduce the dilution properties of the atmosphere. On the other hand, a plume which has enough upward momentum to penetrate partially through the mixed layer reduces the amount of toxic gas material to be dispersed within the mixed layer.

The mixed layer height is typically greatest in unstable conditions, when it can be as high as 1500 to 2000 metres. The mixed layer height is typically lowest in low wind speed stable conditions, when it can be as low as 50 to 100 metres.

The mixed layer height is not a routinely measured factor and must be inferred from other observations.

4.3 Detrimental Effect Factors

This section really accounts for two very important factors in the determination of the detrimental effects to people due to an accidental sour gas release. The first factor is the variation in toxic gas concentration ("fluctuating load") due to the natural turbulence in the atmosphere. The second factor is the human vulnerability to toxic gas exposure ("probit analysis"). Together these two factors give an estimate of the likelihood that people exposed to sour gas during an accidental release would be adversely affected. The following parameters determine the consequences of an accidental sour gas release.

Exposure Time

If a sour gas well blowout were to occur, the toxic effect of H_2S would depend on the length of time people would be exposed to the toxic gas. This exposure time would strongly depend on the delay time for ignition of the sour gas release from a well blowout or the time to deplete a ruptured pipeline segment.

Human Vulnerability to Toxic Gas

Experiments performed on animals and limited documented incidents of accidental human exposures to toxic gas have indicated that both concentration level **and** exposure time are important in defining the potential for an adverse effect. This potential is called the **toxic load**. The toxic load is similar to the concept of **dose**, in that the greater the toxic load that

a person is exposed to, the greater his chances of responding adversely. An increase in **either** toxic gas concentration **or** exposure time will increase the toxic load, however the toxic load is more dependent on changes in concentration than exposure time.

The toxic load concept, and its implementation in human susceptibility modelling, is a large step forward in consequence assessment methodology. Whereas previous work has made extensive use of critical concentration levels, and the hazard zones defined by them, the approach used in GASCON2 accounts for exposure time effects in a realistic way using the toxic load concept.

Variation in Toxic Gas Concentration

Peak concentrations may be several times the average concentration due to the natural turbulent motions of air in the atmosphere. Toxic loads based on average concentrations are not adequate to model adverse effects since the periods of peak concentrations would be severely understated.

The GASCON2 model incorporates a current model for concentration variability in its treatment of detrimental effects. The model is capable of accounting for the peak periods in toxic gas concentration because human vulnerability is modelled as exposure time and H_2S concentration dependent.

Population Density

The potential number of people that can be adversely affected by an accidental sour gas release is dependent on the population density (people per square kilometre) in the exposure zone around a sour gas facility.

5 Frequency Analysis

Frequency analysis is concerned with estimating the likelihood of an accidental sour gas release. This likelihood is expressed as a **frequency** of occurrence of an accident in units of accident events per year. For example, an accident that is estimated to have a frequency of occurrence of 0.00001 accident events per year is equivalent to a frequency of occurrence of 1 accident event every 100,000 years.

The tool used to estimate the frequency of occurrence of an accident is fault tree analysis. This technique focuses on one particular accident event and uses a logical method for determining potential causes and probabilities of the event occurring.

An example of a fault tree can be seen in Figure 6. In this simplified example, an automobile accident is explored for possible causes. In the figure, an automobile accident is assumed to result from **either** a brake failure **or** driver error. A more complete fault tree might consider other causes as well, such as the failure of other equipment. In the example, a brake failure can be caused by **either** inadequate maintenance **or** a faulty brake component. A faulty brake component requires **both** a manufacturing error **and** a factory inspection error.

By assigning or estimating the likelihood of the various sub-events occurring near the bottom of the fault tree (e.g., factory inspection error, improper maintenance in Figure 6), it is possible to follow the fault tree to the top-event (i.e., automobile accident in Figure 6) and estimate a likelihood that it will occur.

In the case of accidental sour gas releases, fault trees were developed for:

- Drilling of wells,
- Non-drilling phase of wells, and
- Pipelines.

The non-drilling phase of wells include producing, suspended, capped, standing, gas injection and storage wells.

The top event in these fault trees is a sour gas release for a given release condition and weather condition. In other words, the occurrence of specific release conditions and weather conditions are sub-events in the fault trees. The probability of these sub-events determine the frequency of the given event. The frequency of the hazard F_H (events/year) must be multiplied by the following probabilities to determine the frequency of an event:

- P_I - probability of non-ignition,
- P_E - probability of a potential emission rate,
- P_G - probability of a potential geometry,
- P_M - probability of a potential meteorology,
- P_θ - probability of winds blowing release from source to receptor during potential meteorology being considered, and
- P_R - probability of receptor being outdoors during exposure.

The various sources of data used in estimating the frequencies were:

- Historical observations of well blowouts and pipeline ruptures in Alberta,
- Historical equipment failure data,
- Engineering reliability calculations,
- Engineering judgement, and
- Meteorological observations.

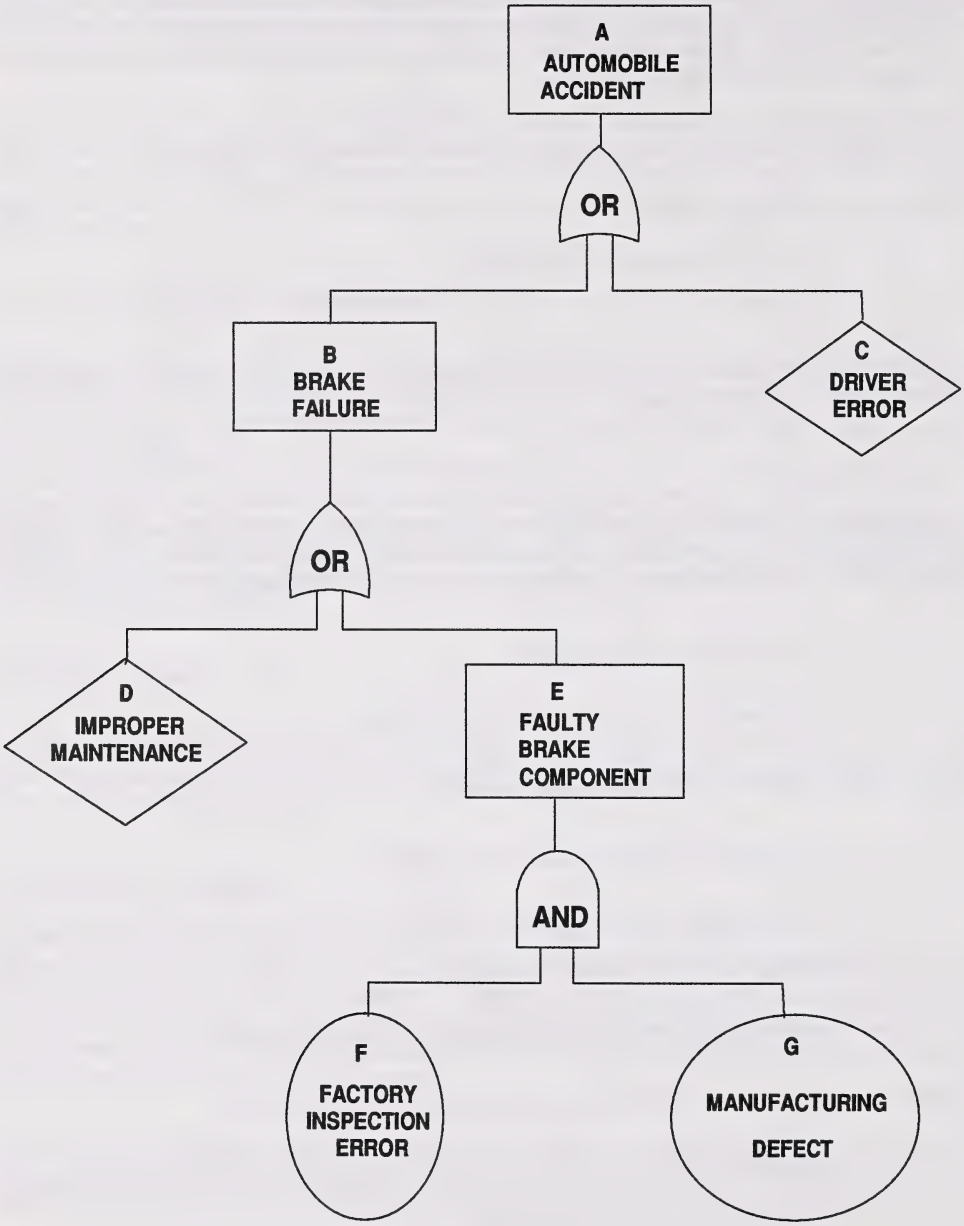


Figure 6

Example of a Fault Tree.

Table 1 summarizes the base case frequency analysis for the given events. The same base cases that were used in GASCON2 appear in the table. The drilling case is for a well flowing up the drill pipe with a downwind jet. The non-drilling cases are for producing and non-producing (suspended, capped and abandoned) wells. They reflect a flow up the tubing with a downwind jet. The pipeline cases are for both ruptures and leaks. The pipeline rupture case is categorized by the flow scenarios outlined in GASCON2.

A sensitivity is done on the base case to arrive at a high and low estimate. These numbers indicate that the frequencies are relatively low for all cases except pipeline leaks, which have less potential for adverse consequences.

Table 1

Frequency Analysis Results.

System	Description	Units	Base Frequency	High Estimate	Low Estimate
Drilling Well	Base Case (Drill Pipe Flow)	Number/Well Drilled	$2.53 \cdot 10^{-9}$ (1 in 370 million)	$1.16 \cdot 10^{-7}$ (1 in 8.6 million)	$5.20 \cdot 10^{-10}$ (1 in 1.9 billion)
Producing Well	Base Case (Tubing Flow)	Number/(Well•year)	$1.32 \cdot 10^{-7}$ (1 in 7.5 million)	$2.01 \cdot 10^{-6}$ (1 in 497 thousand)	$5.21 \cdot 10^{-8}$ (1 in 19 million)
Non-Producing Well	Base Case (Tubing Flow)	Number/(Well•year)	$2.20 \cdot 10^{-8}$ (1 in 45 million)	$2.23 \cdot 10^{-7}$ (1 in 4.5 million)	$9.70 \cdot 10^{-9}$ (1 in 102 million)
Pipeline Ruptures	End Pipe Rupture	Number/(km•year)	$3.63 \cdot 10^{-7}$ (1 in 2.8 million)	$1.52 \cdot 10^{-6}$ (1 in 0.6 million)	$8.00 \cdot 10^{-9}$ (1 in 125 million)
	ESD Valve Rupture	Number/(km•year)	$2.00 \cdot 10^{-9}$ (1 in 500 million)	$1.70 \cdot 10^{-8}$ (1 in 59 million)	$3.37 \cdot 10^{-11}$ (1 in 29 billion)
	Centre Pipe Rupture	Number/(km•year)	$4.13 \cdot 10^{-6}$ (1 in 242 thousand)	$4.52 \cdot 10^{-6}$ (1 in 221 thousand)	$1.03 \cdot 10^{-7}$ (1 in 9.7 million)
	Decay to Steady State	Number/(km•year)	$5.30 \cdot 10^{-8}$ (1 in 18.8 million)	$1.08 \cdot 10^{-7}$ (1 in 9.3 million)	$6.0 \cdot 10^{-9}$ (1 in 166 million)
Pipeline Leaks	Centre Leak	Number/(km•year)	$1.48 \cdot 10^{-4}$ (1 in 6.7 thousand)	$2.69 \cdot 10^{-4}$ (1 in 3.7 thousand)	$6.88 \cdot 10^{-5}$ (1 in 14.5 thousand)

Note: All values refer to an uncontrolled sour gas release for a given probability of non-ignition (P_I), emission rate (P_E), source geometry (P_G) and meteorological condition (P_M).

6 RISK EXAMPLES

The GASCON2 modelling system and the proposed method were used in assessing risks to the public from typical sour gas facilities and for assessing the usefulness of design changes in terms of their impact on safety. Concentration, consequences and risk results are presented for the following scenarios:

Well Parameters

- AOF sour gas release rate of $1000 \cdot 10^3$ m^3/d at sand face.
- Tubing release diameter of 53.4 mm.
- Casing release diameter of 156.3 mm.
- H_2S concentration of 30% in the sour gas.
- Producing operations result in tubing flow.
- Drilling and servicing operations result in casing flow.
- Horizontal jets assumed.

Pipeline Parameters

- Total pipeline length of 6000 m, consisting of one segment or 2 equal segments.
- Pipeline diameter of 254.4 mm.
- Rupture area equivalent to 100% of pipeline area.
- Leak area equivalent to 1% of pipeline area.
- H_2S concentrations of 30% in sour gas.
- Horizontal jet releases from surface pipe associated with ESD valve.
- Cloud releases at 10° to horizontal for buried pipe releases.

Atmospheric Parameters

- Stable atmospheric conditions.
- Wind speed of 1 m/s and a mixing height of 28 m.
- Flat or gently rolling terrain covered by mature agricultural crops.
- Frequency based on observations at Calgary International Airport.
- Winds from west.

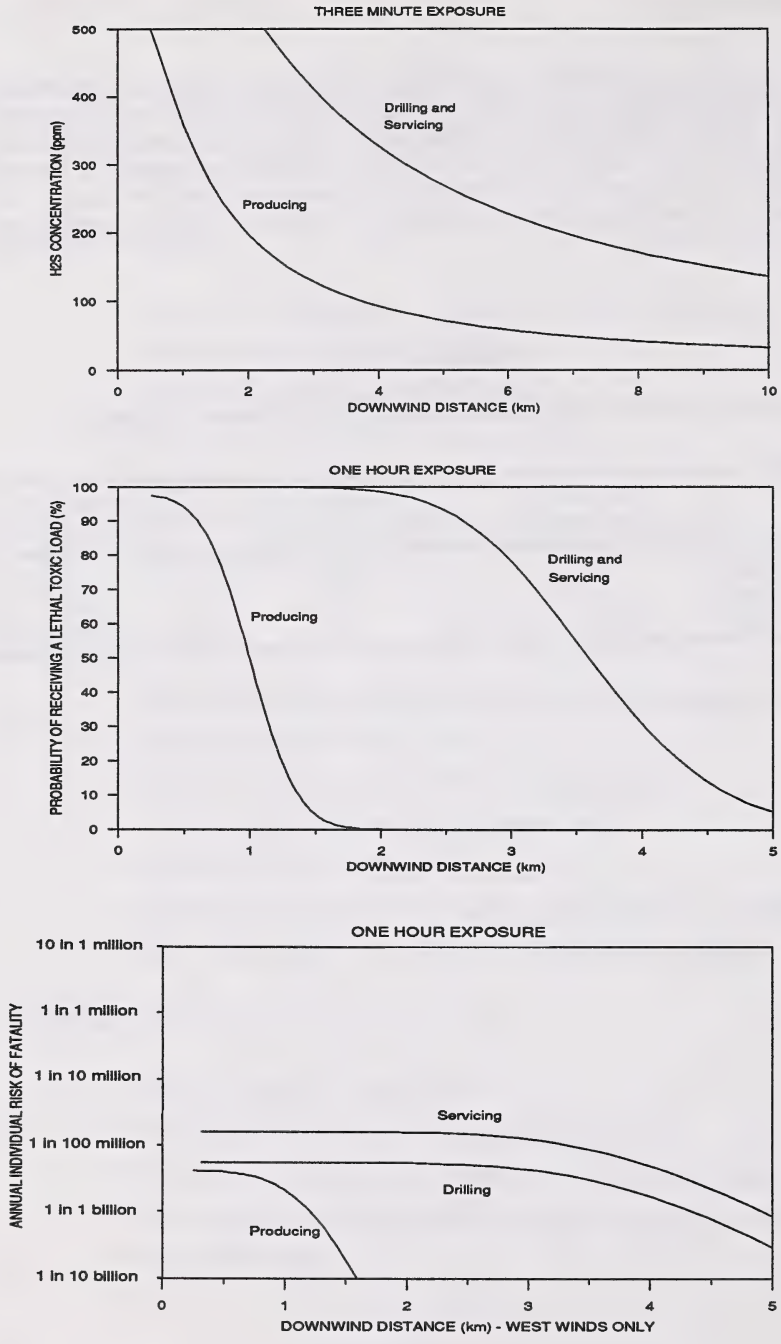
Well Blowout Predictions

Table 2 gives the frequency and the societal risk and Figure 7 gives the concentration, consequences and individual risk of the events modelled. The concentration and consequence for drilling and servicing operation are the same. However, the frequency of blowouts during servicing is higher than for drilling, so the risk is greater. The producing phase of operation has the lowest risk. Societal risk for production operations is considerably less as the number of people exposed to the release is less, since lethal concentrations do not extend as far downwind.

Table 2

Frequency and Societal Risk for Selected Well Blowout Scenarios.

	Frequency (events/year)	Consequences (fatalities/event)	Societal Risk (fatalities/year)
Drilling	$5.6 \cdot 10^{-9}$	37	$2.1 \cdot 10^{-7}$
Producing	$4.2 \cdot 10^{-9}$	5	$2.1 \cdot 10^{-8}$
Servicing	$1.6 \cdot 10^{-8}$	37	$5.9 \cdot 10^{-7}$



Concentration (Note x-scale change from graphs below)

Consequence

Risk

Figure 7

Predicted H_2S Concentrations, Probability of Lethality and Risk of Fatality for Selected Well Blowout Scenarios.

Pipeline Leaks and Ruptures

Table 3 gives the frequency and societal risk and Figure 8 gives the concentration, consequences and individual risk of the events modelled.

The 6 km buried pipeline results in the highest H_2S concentrations and consequences; however, leaks from buried pipelines result in zero predicted probability of receiving a lethal toxic load and zero potential fatalities.

The 3 km buried pipeline has lower concentrations and thus lower consequences than the 6 km buried release and the 3 km surface release. Note that the frequency for the two 3 km buried sections is the same as for the 6 km buried section.

The leak from surface pipe results in an exposure zone which extends 1 km downwind and results in 0.03 potential fatalities. Leaks have the highest frequency but lowest consequences, thus their contribution to risk is low.

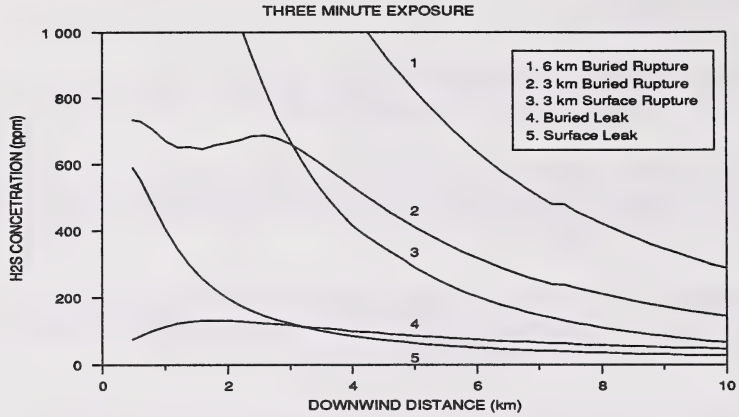
To determine the system risk, the risk from each release type from each component of the system must be added. For the scenario without the valve, risk is the sum of the risk due to leaks and ruptures. Similarly, when the valve is considered, the contribution to risk from leaks and ruptures in each of the 3 km buried sections and in the surface pipe are added.

For the pipeline parameters modelled, the installation of an additional ESD valve reduces the societal risk by about a factor of 18 and the maximum individual risk by about a factor of 2.

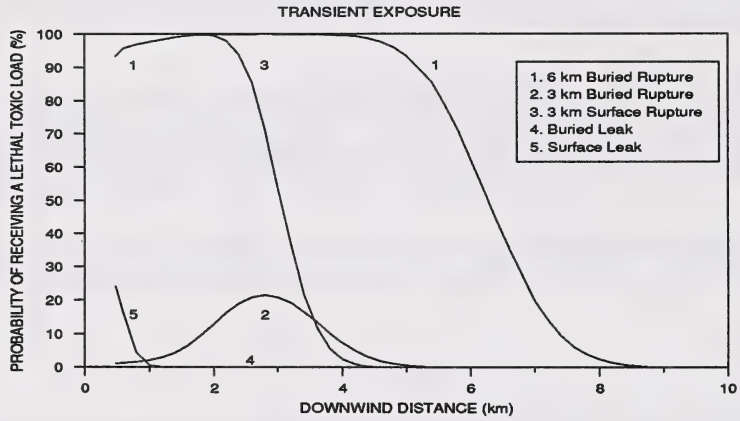
Table 3

Frequency and Societal Risk for Selected Pipeline Leak and Rupture Scenarios.

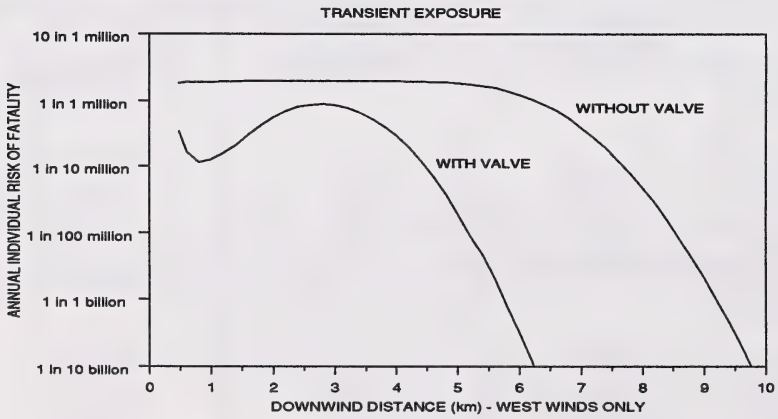
	Frequency (events/year)	Consequences (fatalities/event)	Societal Risk (fatalities/year)
Before No ESD Valve			
Buried Leaks	$8.3 \cdot 10^{-4}$	0.0	0.0
Buried Ruptures	$1.3 \cdot 10^{-5}$	31	$4.1 \cdot 10^{-4}$
Total	N/A	N/A	$4.1 \cdot 10^{-4}$
After With ESD Valve			
Buried Leaks	$8.3 \cdot 10^{-4}$	0.0	0.0
Surface Leaks	$1.1 \cdot 10^{-5}$	0.03	$2.9 \cdot 10^{-7}$
Buried Ruptures	$1.3 \cdot 10^{-5}$	1.4	$1.9 \cdot 10^{-5}$
Surface Ruptures	$2.9 \cdot 10^{-7}$	14	$4.1 \cdot 10^{-6}$
Total	N/A	N/A	$2.3 \cdot 10^{-5}$



Concentration



Consequence



Risk

Figure 8

Predicted H_2S Concentrations, Probability of Lethality and Risk of Fatality for Selected Pipeline Leak and Rupture Scenarios.

7 CONCLUDING REMARKS

A method has been developed to estimate individual and societal risk for an incident. The two key inputs are:

(i) the consequences of a sour gas release event from uncontrolled well blowouts or pipeline ruptures (from the GASCON2 model) and,

(ii) the expected frequencies of such events.

In practical applications, the degree of risk reduction possible as estimated by GASCON2 for the various alternative designs for a facility can be weighed against the cost of the various designs so that informed risk management decisions can be made. In such decisions at least one other factor, apart from the risk and cost factors, must also be considered. This factor consists of the socio-political considerations, which include value judgements as to the acceptability of a given level of risk. This requires input from the public.

1 INTRODUCTION

This report describes a risk assessment approach which can be used to estimate the risks to public safety posed by potential uncontrolled sour gas releases. This risk assessment approach provides an extension to a previously-developed hazard and consequence assessment model, named GASCON2, which was described in a previous report (Alp *et al.* 1990). GASCON2 is used to estimate downwind distance concentration profiles, potential exposure zones, the probability that concentrations of H_2S occurring downwind are lethal, and the potential number of fatalities associated with an uncontrolled release of sour gas. This report provides estimates of the frequency of occurrence of an uncontrolled release. Risk assessment is a tool to assist in determining buffer zones or setback distances and land use near sour gas facilities in Alberta.

This report deals with Phase II of a project conducted on behalf of the Energy Resources Conservation Board as part of their continuing evaluation of sour gas development and public safety concerns. The Phase I report documenting the development and evaluation of GASCON had already been submitted (Alp *et al.* 1987) and was revised and renamed to GASCON2 (Alp *et al.* 1990). A Scientific Advisory Board appointed by the Energy Resources Conservation Board provided a technical and peer review throughout Phases I and II to ensure the scientific acceptability of the work. In most cases, current modelling approaches were employed; in some instances, new approaches were adopted to address the unique character of uncontrolled sour gas releases.

1.1 Background

By incorporating mathematical models representing the current understanding of high pressure gas jet releases, plume rise and atmospheric dispersion, the GASCON2 model can be used to predict with more confidence than previous models the downwind concentrations of toxic gas (H_2S or SO_2) resulting from an uncontrolled release of sour gas (unignited or ignited) (Alp *et al.* 1990).

For a given release event, defined by the sour gas release emission, release geometry and meteorological conditions which give rise to downwind concentrations of toxic gas, the probit analysis and fluctuating load analysis permit the consequences of the H_2S concentrations to be quantified. To arrive at the risk to the human population in the vicinity of the release, however, one must quantify the frequency of that release event occurring.

A hazard and consequence assessment model, as has been developed in Phase I, allows one to examine realistically possible uncontrolled sour gas release events to determine the worst-case scenario. The trouble with "realistically possible" events is that "conceivable" events are sometimes extremely unlikely events. Also, it is generally not practical to make planning decisions based on "worst-case" outcomes; if people adopted worst-cases as the basis for their decision-making, nothing would ever get done for fear of the possible outcomes. Almost any activity that would come to mind would be fraught with disastrously possible (but unlikely) consequences.

It is important to recognize that a worst-case outcome cannot of itself give a rational measure of danger to the public; it must be viewed in the context of the chances of such a worst-case outcome occurring. When one speaks of the chances of an adverse outcome occurring, one is referring to **risk**.

Risk is an inseparable part of life - each person lives with the knowledge that an unexpected event may intervene at any time in his or her life and that some events are more likely to happen (i.e., are riskier) than others.

Risk analysis of environmental hazards has developed as a system for estimating the quantitative (numerical) probabilities associated with events and their consequences to the people, machines, buildings or natural environment affected by those events. Risk analysis is intended to provide data for decision-making with regard to activities or technologies that entail potentially significant levels of risk. Quantitative risk estimates for a technological activity can be evaluated along with costs, benefits, risks of alternatives and mitigating measures in the decision-making process. The process of developing the risk values is generally called risk assessment and judging the risk values along with the qualifying factors is generally referred to as risk management. The two complementary parts of the decision-making process: risk assessment and risk management are depicted in Figure 1.1, as taken from a recent report prepared by the U.S. National Research Council (NRC, 1983).

This report describes research and risk assessment activities related to sour gas production, which are required to make informed risk management decisions, as shown in Figure 1.1. In order that regulatory agencies can make rational decisions regarding safety precautions and emergency planning, and in order that members of the public can follow the rationale for those decisions, it is best that quantifiable estimates of the risk to public safety be made available to all interested parties. Once a measure of the risk posed by a sour gas facility is in hand, mitigative measures can be assessed in a quantitative manner, and the estimated level of risk can be incorporated into the decision-making process.

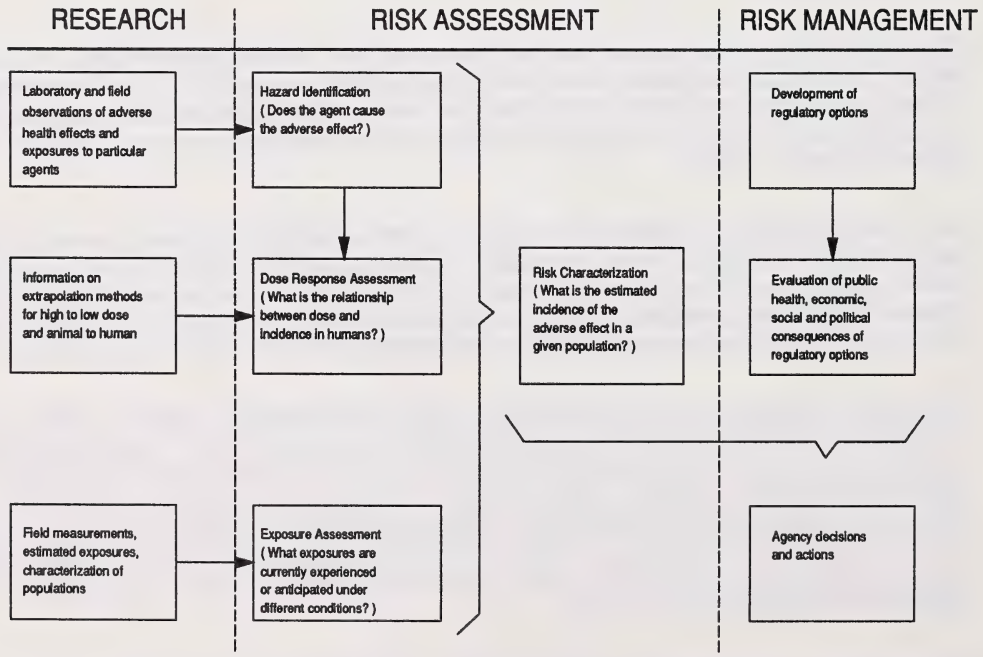

RESEARCH
RISK ASSESSMENT
RISK MANAGEMENT
Laboratory and field observations of adverse health effects and exposures to particular agents
Hazard identification (Does the agent cause the adverse effect?)
Development of regulatory options
Information on extrapolation methods for high to low dose and animal to human
Dose Response Assessment (What is the relationship between dose and incidence in humans?)
Risk Characterization (What is the estimated incidence of the adverse effect in a given population?)
Evaluation of public health, economic, social and political consequences of regulatory options
Field measurements, estimated exposures, characterization of populations
Exposure Assessment (What exposures are currently experienced or anticipated under different conditions?)
Agency decisions and actions

Figure 1.1

Risk Assessment and Risk Management Process.

1.2 Objectives

The overall objective of Phase II of this project is the development of an approach for estimating risk to safety from uncontrolled sour gas release events. This development process includes:

- Selecting a scientifically sound approach,
- Evaluating historical data to determine the frequency of uncontrolled sour gas releases,
- Incorporating the frequency analysis with the GASCON2 hazard and consequence assessment model into a risk assessment method,
- Applying the method to the various worst-case conditions identified in the Phase I report, and
- Providing a scientific reference document for the approach and evaluation stages.

This report fulfills the last objective in documenting the development and evaluation of the risk assessment approach.

1.3 Project Organization

The project described in this report was done under contract to the Energy Resources Conservation Board (ERCB) by Concord Environmental Corporation. A Scientific Advisory Board was appointed by the ERCB to provide a technical and peer review of the project.

The **Environment Protection Department** of the **ERCB** was responsible for the co-ordination of the project. The Environment Protection Department provides information and advice to other operating departments within the ERCB on air and water quality, land management, and emergency response planning concerns. The responsibilities of the ERCB in Alberta include:

- Approving applications for new energy projects,
- Regulating the operation of existing energy facilities, and
- Providing advice and information to industry, the public and government.

The ERCB works closely with Alberta Environment to ensure that environmental impacts resulting from the operation of proposed and existing energy developments are acceptable.

Concord Environmental Corporation is a professional services firm with expertise in environmental sciences and technology. Concord has offices in Toronto, Ottawa, Calgary and Vancouver. Concord has considerable experience in the development and application of models to help resolve air pollution problems. Two examples include:

- The development of a dispersion model to predict hazard zones created by toxic or flammable heavy gas releases (Alp, 1985).

- The development of a modelling system for simulating long range transport and acidic deposition (commonly called acid rain) (USEPA and AES, 1987).

Specifically, the Concord project team has expertise in the following areas required for the review and development of modelling systems.

- Fluid flow,
- Dispersion meteorology,
- Mathematical modelling,
- Toxic chemicals, and
- Risk Assessment and Management.

A **Scientific Advisory Board** appointed by, and reporting to, the Energy Resources Conservation Board, provided a technical and peer review component throughout the project to assure the scientific acceptability of the overall approach and the specific assumptions embodied in the modelling system. Members of this Board include:

- Dr. D. Wilson is a professor in the Department of Mechanical Engineering at the University of Alberta. His research activities relate to the following areas: turbulent fluid dynamics, atmospheric dispersion, residential energy losses from air infiltration, turbulent concentration fluctuations and pipeline rupture assessments.

- Mr. R. Angle is the Section Head of Scientific Applications, Air Quality Control Branch, Alberta Environment. Mr. Angle is a meteorologist with experience in the following areas: acid deposition, air pollution modelling, risk analysis, atmospheric chemistry, instrumentation guidelines and air quality impact assessments.

- Dr. R. Purvis is Manager of the Special Studies Group at the Energy Resources Conservation Board. He has experience in drilling, production and reservoir engineering in western Canada. His current work involves the development and implementation of computer software to engineering applications.

- Dr. R. Rogers is president of Toxcon Consulting Ltd. located in Sherwood Park. He has experience in the areas of environmental and industrial toxicology and occupational health. He is also an instructor at Concordia College.

The expertise of the Scientific Advisory Board members address the major technical aspects associated with evaluating the impact of uncontrolled sour gas releases.

2 RISK ASSESSMENT METHODOLOGY

The terms "hazard assessment", "consequence assessment" and "risk assessment" which appear in this report are defined as:

- **Hazard assessment** deals with establishing the physical influence of an accidental event. For example, if an uncontrolled release of sour natural gas from a well blowout or pipeline rupture were to occur:

  - *What would the concentration of H_2S be at locations downwind of a release point?*

  - *How large would the hazard zone where H_2S concentrations exceed a criteria level be?*

- **Consequence assessment** estimates the detrimental effects that the accidental event could produce. The detrimental effect of primary concern is human fatality. The questions answered for a given event are:

  - *What would the probability of receiving a lethal toxic load (dose) of H_2S at locations downwind of a release point be?*

  - *How many potential fatalities could occur if there were people outdoors during the release?*

- **Risk assessment** determines the likelihood that an adverse consequence (human fatality) will occur due to an accidental event. Risk assessment answers the question:

  - *What are the chances of human fatalities due to an accidental event?*

2.1 Elements of Risk Assessment

Figure 2.1 shows the general elements which make up a risk assessment. Foremost in the scheme is the identification of an uncontrolled sour gas release event. For the purposes of this work, an **uncontrolled sour gas release event** (or **event**, for short) is defined as the combination of sour gas source and meteorological conditions which completely determine the influence of the sour gas release on the surroundings. This definition is consistent with the one used in the Phase I report (Alp *et al.* 1990). The two fundamental portions of a risk assessment are the **frequency analysis** and the **consequence analysis**.

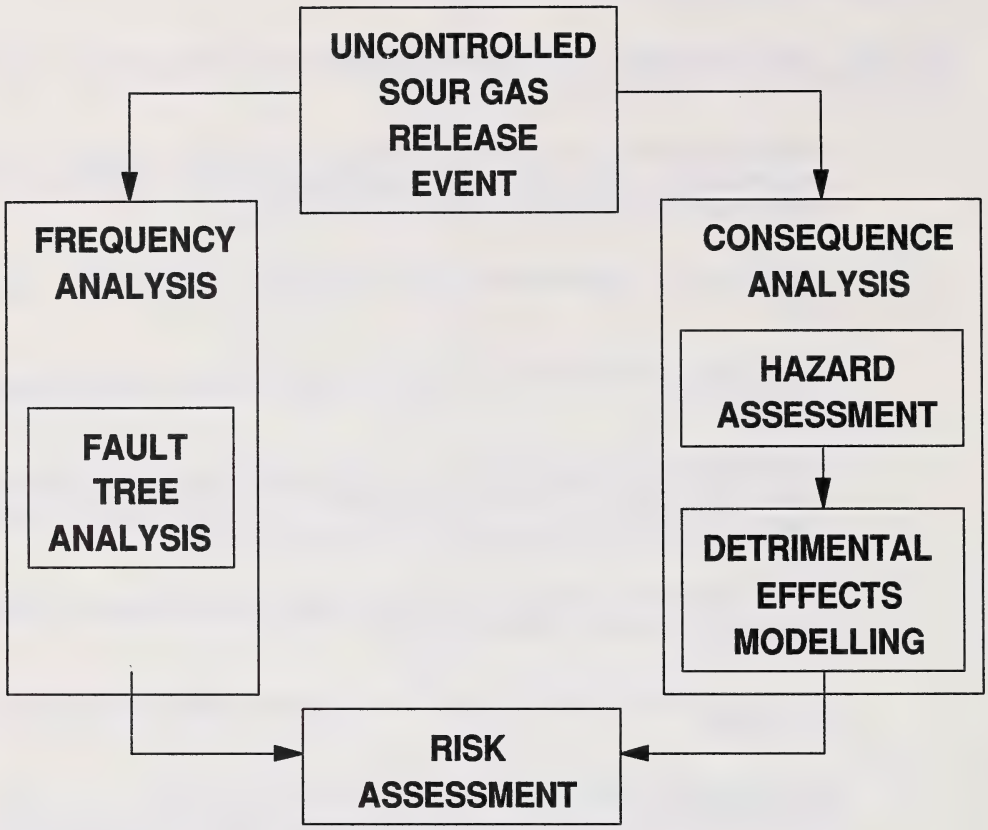


Figure 2.1

General Risk Assessment Elements.

The consequence analysis in Figure 2.1 estimates the detrimental effect of an uncontrolled sour gas release. Hazard assessment is used to estimate the extent of influence of the release and detrimental effects modelling is used to estimate the consequences of the release. The detrimental effect of concern for this risk assessment of uncontrolled sour gas releases is **lethality** to humans; that is, the potential for human fatality due to exposure to, and inhalation of, the toxic sour gas component (H_2S). The consequence analysis indicated in Figure 2.1 is the application of the GASCON2 model.

The frequency analysis estimates the frequency of occurrence of a release event; in other words, how likely is it that a specific release event could occur? The main tool of the frequency analysis is a technique called fault tree analysis, which is described in detail in Section 3. Briefly, fault tree analysis deals with the development of a diagram which shows the chain of subevents which must occur for a release event to occur. By assigning known or estimated frequencies of occurrence to the subevents, the fault tree can be used to estimate the frequency of occurrence (events per year) of the release event.

2.2 Consequence Analysis

Figure 2.2 shows the flowchart for the GASCON2 model, which can be viewed as a modelling framework. Inputs to and outputs from the main modelling system are identified; for a detailed description of these elements, the reader is referred to Alp *et al.* (1990). The main modelling system consists of six major modules, each dealing with a different stage or aspect of the sour gas release. The mathematical relationships governing these modules are also detailed in Alp *et al.* (1990).

Included in the GASCON2 framework is a meteorological preprocessor to calculate parameters which characterize dispersion in the atmosphere (for example, atmospheric stability and mixed layer height) from routine meteorological observations collected at surface meteorological stations. Output from the preprocessor is required by the main modelling system.

GASCON2 is a hazard and consequence assessment model which predicts the downwind toxic gas (H_2S or SO_2) concentrations and consequences due to H_2S for a given uncontrolled sour gas release event. In this context "event" is taken to mean the combination of emission conditions (e.g. well deliverability, pipeline dimensions, pipeline operational parameters, etc.), geometry conditions (e.g. horizontal jets, vertical jets, leaks, clouds, etc.) and meteorological conditions (e.g. atmospheric stability, wind speed, etc.). Not all events are equally likely, but given that a particular event were to occur, GASCON2 can predict the downwind toxic gas concentrations and consequences associated with that input event. Examples of these predictions appear in Alp *et al.* (1990).

2.3 Individual Risk and Societal Risk

As used in this study, **individual risk** is the likelihood or frequency that a person will receive a lethal exposure of H_2S from an uncontrolled sour gas release. This probability will vary from one downwind location to another, since the H_2S concentrations are location dependent. Individual risk is expressed as the probability of fatality per year for an exposed individual. In this work, the individual risk is reported for a specific release event, whose frequency of occurrence is known from the frequency analysis portion of the risk assessment. Individual risk is not summed over all possible release events or locations.

As used in this study, **societal risk** is an estimate of the frequency of human fatalities which could result from uncontrolled sour gas releases. This may be viewed as the sum of the individual risks of all the people in the area exposed to the sour gas release. Societal risk is expressed as the number of estimated fatalities in a specified period of time, in an exposed group. In this work, societal risk is reported for a specific release event whose frequency of occurrence has been estimated. Societal risk is not summed over all possible release events or locations.

The approach described in this report determines **incident risk**, that is, risk for a given uncontrolled sour gas release event. **Facility risk** is the sum of the incident risks for all of the possible release events and locations.

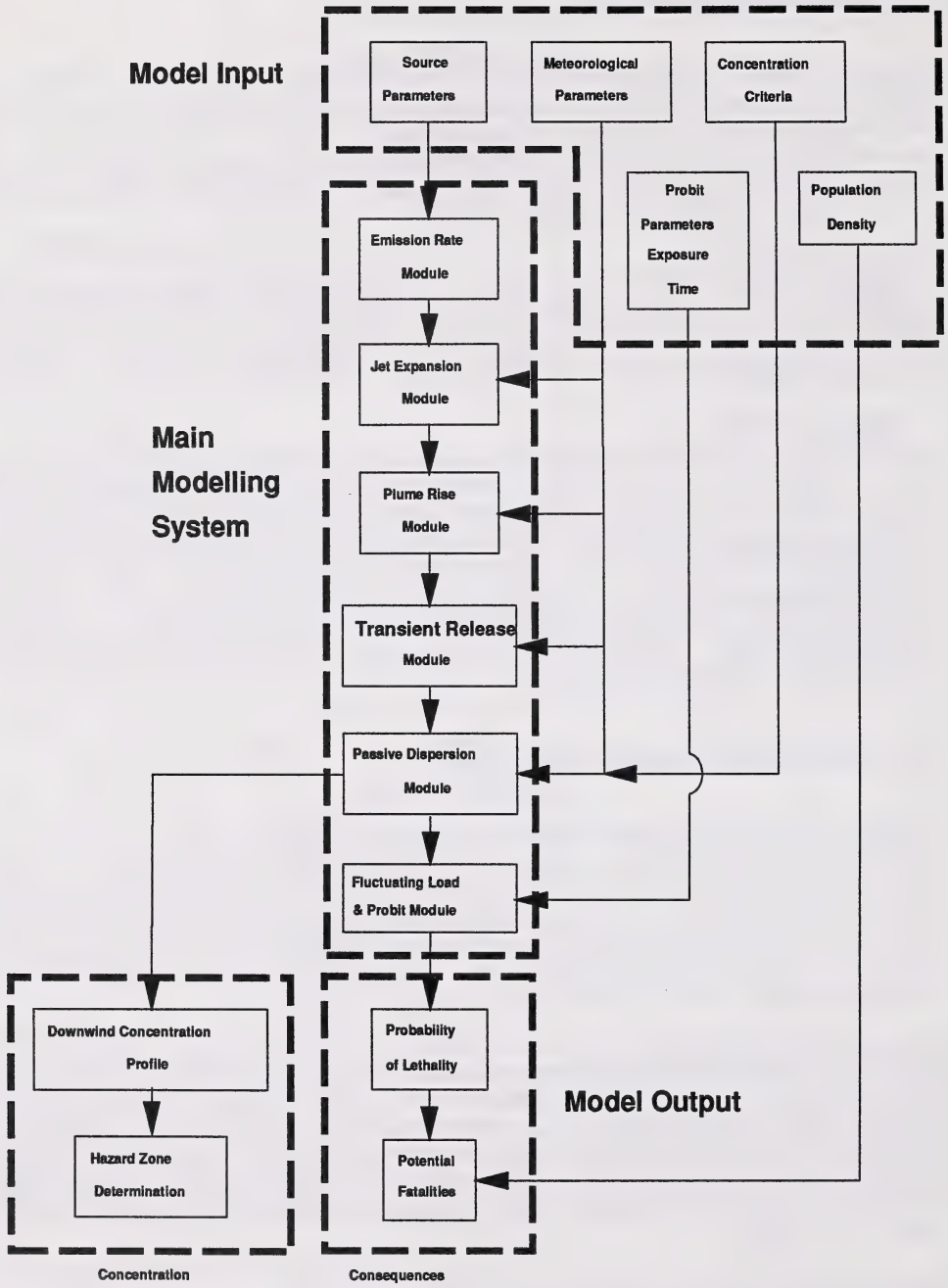


Figure 2.2

Detailed GASCON2 Modelling Framework.

2.3.1 Risk Calculations

Risk is a measurement of both the frequency of occurrence of an event **and** of the magnitude of the consequences of that event. This may be expressed as:

Risk = Frequency x Consequence

The event consequences provided by GASCON2 are:

$P_{L_{ijkl}}(x,y)$ = probability of receptor located outdoors at position (x,y) recieving a lethal toxic load of H_2S from event defined by hazard i, emission rate j, geometry k and meteorological condition l.

$N_{F_{ijkl}}$ = potential fatalities due to H_2S for outdoor receptors if event defined by hazard i, emission rate j, geometry k and meteorological condition l were to occur (fatalities/ event).

Hazards (i) refer to releases from wells, buried pipelines and surface facilities. Emission rate (j) is determined by the release area or source conditions. Geometry scenarios (k) include vertical jets, horizontal jets and clouds. Meteorological conditions (l) include stable, neutral and unstable with representative wind speeds. It is important to note that the release is not ignited and the receptors are outdoors.

The frequency of an event described by the specific combination of hazard i, emission rate j, geometry k and meteorological condition l must be used to determine the risk due to that event. This is the joint probability of the specific combination of conditions occurring. To determine the risk to a receptor at (x,y), the probability of the winds blowing the release event from the source (0,0) to the receptor $P_{\theta_{lm}}(x,y)$ must also be considered.

Individual risk for an event is given by:

$$R_{I_{ijkl}}(x,y) = F_{H_i} P_{I_i} P_{E_j} P_{G_k} P_{M_l} P_{\theta_{lm}}(x,y) P_R P_{L_{ijkl}}(x,y)$$

where:

$R_{I_{ijkl}}(x,y)$ = individual risk of fatality due to H_2S for outdoor receptor at position (x,y) for hazard i, emission rate j, geometry k and meteorological condition l (chances of fatality/ year).

F_{H_i} = frequency of hazard i (number/ year).

P_{I_i} = probability of non-ignition for hazard i.

P_{E_j} = probability of emission rate j for hazard i.

P_{G_k} = probability of geometry k for hazard i.

P_{M_l} = probability of meteorological condition l.

$P_{\theta_{lm}}(x,y)$ = probability of wind direction m, from source (0,0) to receptor (x,y) during meteorological condition l.

P_R = probability of receptor being outdoors.

Similarly, societal risk for an event is given by:

$$R_{S_{ijkl}} = F_{H_i} P_{I_i} P_{E_j} P_{G_k} P_{M_l} P_{\theta_{lm}}(x,y) P_R N_{F_{ijkl}}$$

where:

$R_{S_{ijkl}}$ = societal risk of fatality due to H_2S for outdoor receptors for hazard i, emission rate j, geometry k and meteorological condition l (fatalities/year).

For pipelines, the frequency F'_{H_i} of ruptures and leaks is expressed as (number/km•year). The following formula is used to convert the frequency:

$$F_{H_i} = LF'_{H_i}$$

where:

F_{H_i} = frequency of hazard i (number/km•year)

L = representative length, normally taken as blowdown length (km).

3 FREQUENCY ANALYSIS

Frequency analysis quantifies the frequency of occurrence of a given accident event expressed in terms of accident events per year. For example, an accident event that has been observed to occur once in ten years has a frequency of occurrence of 0.1 accident events/year.

Frequency analysis has been incorporated in previous risk assessment studies associated with sour gas facilities in Alberta (Atwell *et al*, 1979; Angle, 1982). These studies relied solely on historical data for estimating the frequency of occurrence for sour gas releases. In 1984, the Blowout Prevention Review Committee (BPRC) was created in response to the Lodgepole well blowout to provide a detailed technical review of matters related to well blowout prevention. A BPRC subcommittee identified and reviewed selected factors which could affect the likelihood of a blowout problem associated with the drilling of critical sour gas wells (BPRC, 1986).

A tool often used to estimate the frequency of occurrence for an accident is the **Fault Tree Analysis** (FTA) technique. This technique focuses on one particular accident event and provides a logical method for determining potential causes and probabilities of the event occurring. The FTA approach has been used in Alberta for risk analysis studies associated with uncontrolled sour gas releases (Bercha, 1983; Bercha, 1985; Bercha, 1986). These studies, along with the BPRC subcommittee findings, provided a foundation for this frequency analysis.

The approach followed was to first review previous sour gas risk assessment studies. Since FTA was recognized as the most important analysis tool, a detailed review of Bercha Risk Assessments was completed. Information from these studies on fault tree structure, statistical data or assumptions, that were felt to be useful, were incorporated in this study. This frequency analysis was completed prior to Bercha's more recent pipeline fault tree work for the Caroline hearing in April 1990. Therefore any further advancements by Bercha were not incorporated. Where the levels of detail or structure were felt to be adequate, those components were incorporated into the fault trees developed for this study.

For this study, historical data tabulated by the ERCB, as well as data from other studies and the open literature, were used to quantify fault trees associated with uncontrolled sour gas releases from well blowouts and pipeline ruptures. Where possible, data specific to sour gas operations was obtained from the ERCB. Separate consideration was given to well blowouts resulting from drilling and non-drilling operations and to pipeline failures resulting from both leaks and ruptures.

As described in the GASCON2 report (Alp *et al*, 1990), the downwind toxic gas concentration profiles resulting from uncontrolled H_2S releases are dependent on:

- Emission rate,
- Release geometry, and
- Meteorological conditions.

The frequency of occurrence of an uncontrolled H_2S release event ($F_{H_{ijkl}}$) defined by a given emission rate, release geometry and meteorological condition is then dependent on the:

- Frequency of an accident (e.g. well blowout or pipeline rupture) (F_{H_i}),
- Probability of ignition of the escaping sour gas stream (P_{I_i}),
- Probability of a potential emission rate (P_{E_j}),
- Probability of a potential release geometry (P_{G_k}), and
- Probability of a potential meteorological condition (P_{M_l}).

The release event frequencies, where possible, were estimated for sour gas wells and pipelines using the FTA technique which is discussed in Section 3.1. The frequency procedures and the estimated release event frequencies for sour gas well and pipeline cases are given in Sections 3.2, 3.3 and 3.4. An example of how the probability of a given meteorological condition occurring can be estimated is presented in Section 3.5. Finally, estimates of the uncertainty associated with the event frequencies results obtained using the frequency analysis approach are presented in Section 3.6.

3.1 Fault Tree Analysis

A fault tree is a graphical representation of the chain of events linking the top event with the basic event causes. Beginning with the top event, reverse logic is used to determine what causal factors can lead to the top event if it was to occur. If a causal factor itself can be caused by several other factors, it is considered a **subevent** in fault tree terminology. If a causal factor is a basic initiating cause it is considered a **basic event**. At times it is desirable not to develop a subevent further, either to simplify a fault tree or due to lack of data to quantify the basic event. This is considered an **undeveloped event**. A fault tree can show several failure sequences of events that lead to the top event.

A simplified example of a fault tree is given in Figure 3.1. In the example, an automobile accident (top event A) is assumed to result from either a brake failure (subevent B) **or** driver error (subevent C). A brake failure can be caused by either improper maintenance (subevent D) **or** a faulty brake component (subevent E). The occurrence of a faulty brake component requires both a factory inspection error (basic event F) **and** a manufacturing defect (subevent G). In the example, subevents C and D are treated as undeveloped events and subevents F and G are treated as basic events.

Events within a fault tree are joined by logic gates. The various events and logic gates are shown in Appendix A. Logic gates show the interaction between input events located below the logic gates and the resultant output event located above the logic gate. The main logic gates are the AND gate and the OR gate. The output from an AND gate occurs only if **all** input events occur. The output from an OR gate occurs if **any** input event occurs.

Boolean algebra equations can be developed for each logic gate to allow quantification of the output event from the frequency data (event/year) and/or probability data (dimensionless) of the input events. Referring to Figure 3.1, the probability of the top event *A* and subevent *E* occurring are given by (*P* refers to probability):

$$\text{OR gate.....} \quad P(A) = P(B) + P(C) - P(B) \cdot P(C) \tag{3.1}$$

$$\text{AND gate....} \quad P(E) = P(F) \cdot P(G) \tag{3.2}$$

When events are mutually exclusive or their magnitude is small (< 0.05), Equation 3.1 for the OR gate can be written without the product term.

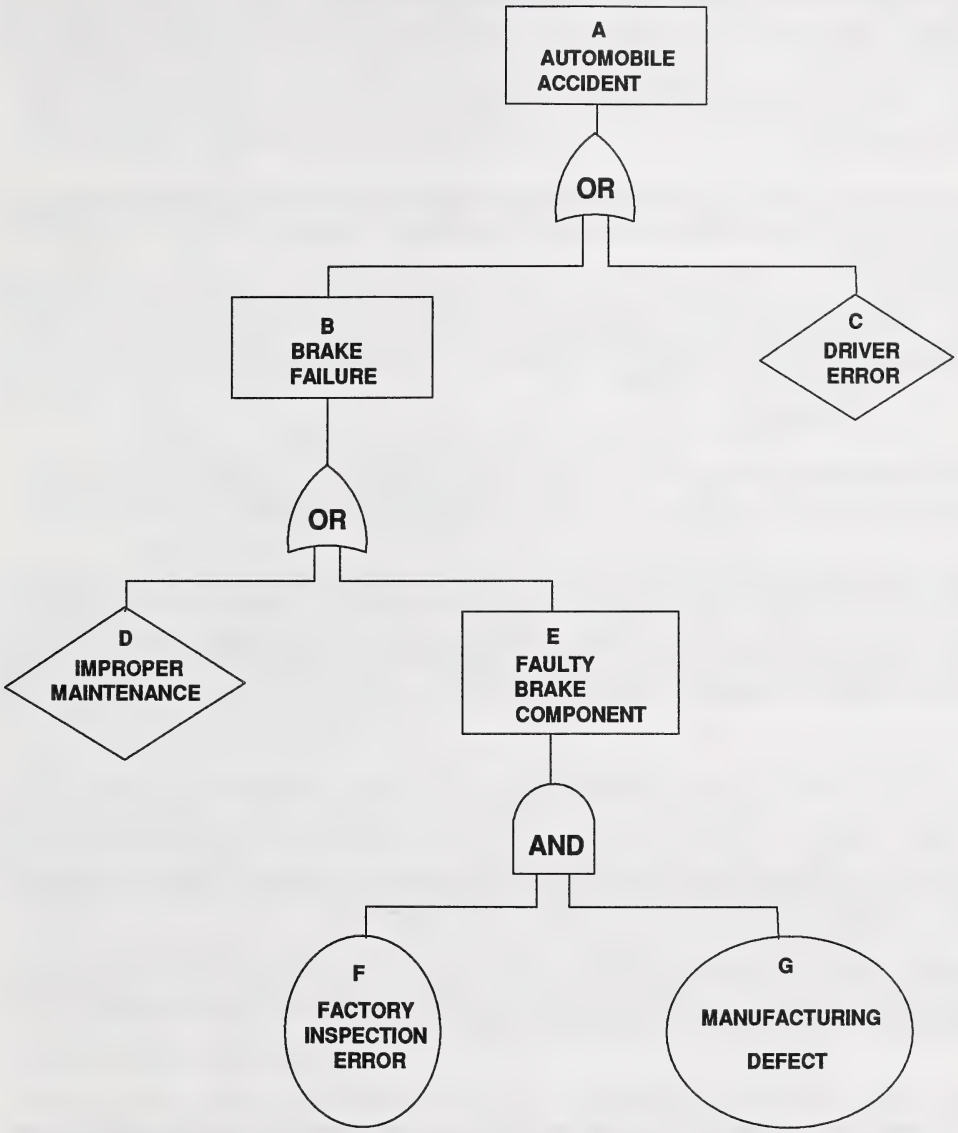


Figure 3.1

Example of a Fault Tree.

FTA can be of value qualitatively by highlighting failure pathways. Potential mitigative measures that can lead to a reduction in the frequency of occurrence of the top event may become more apparent. Mitigative measures that are suggested to reduce risk by possibly reducing the frequency of occurrence of an undesired event can be easily evaluated using FTA. The analysis can be extended to incorporate contributing operator error as well as equipment failures.

For FTA to be used as a quantitative tool, the frequencies of occurrence and probabilities of all basic and undeveloped events must be known or estimated. This will require a combination of:

- Historical failure data analysis,
- Engineering reliability analysis,
- Operator error analysis, and
- Judgement.

Historical failure data are the best source for quantifying basic and undeveloped events. These data should be specific to the system and operating procedures under investigation.

Engineering reliability analysis is useful when analysing protective systems. Component failure rates (k) obtained from historical failure data and the time between component inspections (t) can be used to quantify the Fractional Down Time (F_{DT}) or the probability that a protective device will not operate successfully when demanded. A simplified equation for the estimation of F_{DT} given by Kletz (1986) is:

$$F_{DT} = \frac{k \cdot t}{2} \tag{3.3}$$

Equation 3.3 indicates that the more frequent inspection of protective systems will increase their probability of operating successfully when demanded.

Operator error analysis is a technique used to calculate human error contribution to system failure. The procedure is exhaustive and may not be suitable for many situations. As an alternative, general operator error probabilities can also be used.

When dealing with basic or undeveloped events for which no failures have been recorded over the time period for which the historical database was gathered, the above methods are insufficient. This, however, does not mean that the actual frequency of occurrence for those events is zero. The fact that these events have been identified in the fault tree indicates that their frequency of occurrence is non-zero. For relatively small probabilities, zero frequencies may be arbitrarily assigned. Alternatively, estimated frequencies based on judgement or other data can be assigned to ensure that the frequency of occurrence of the top event is conservatively estimated.

The fault trees for this Risk Approach document were developed independent of data availability. The intent was to develop them to a sufficient level of detail to determine the most significant failure mechanisms. Data were subsequently obtained from the ERCB files in a form amenable to the quantification of the fault tree. The data available usually filled the top of the fault trees indicating areas where data might need to be collected in the future.

Both the development and quantification of the fault trees involved discussions with the ERCB staff and consultants who understand sour gas well and pipeline systems and the historical data associated with these systems.

3.2 Frequency Analysis for Drilling Wells

3.2.1 Description of Drilling Well Fault Tree

Figures A.1a, A.1b and A.1c in Appendix A show the fault tree developed for drilling wells. The top event (Event Box A1) is an uncontrolled sour gas release from a well blowout during drilling for a given emission rate (Event Box X1), release geometry (Event Box X2) and meteorological condition (Event Box X3). The frequency of occurrence for this event can be estimated knowing the:

- Frequency of occurrence of an uncontrolled well blowout F(A2),
- Probability of the blowout not being ignited P(A46),
- Probability of a potential emission rate P(X1),
- Probability of a potential release geometry P(X2), and
- Probability of a potential meteorological condition P(X3).

The fault tree presented here represents a greater level of detail than what has been developed in previous studies (Bercha, 1983 and 1985). The main enhancing feature is the inclusion of emission rate, geometry, meteorology and non-injection probabilities, allowing the specification of well defined events. In addition, failure to control a kick is treated in more detail. Further, factors that modify global (Alberta) frequencies for specific applications have also been an important addition.

An uncontrolled well blowout results from a surface release or blow (Event Box A3) that cannot be controlled quickly by the drilling crew. When a blow occurs, the crew must quickly inject enough fluid into the borehole to allow the well to be shut-in without exceeding the maximum allowable casing pressure. Failing to accomplish this quickly may cause equipment to fail due to the strong forces exerted by the high velocity fluid and lead to an uncontrolled well blowout. Once a blow occurs, potential mitigative procedures initiated by the drilling crew to control the well are a hopeful solution at the best. In this study, as in previous studies, failing to control a blow is treated as an undeveloped event. Reliable data required to support a more detailed analysis would be extremely difficult to obtain and highly subjective in nature. This analysis focuses on the root causes of blowouts where mitigative measures are more effective.

The initiating and most important subevent leading to a blow is a kick (Event Box A4), or influx of formation fluids into the wellbore. Through proper detection and handling of kicks, drilling operations can be restored to normal. As a result, the frequency of occurrence of kicks and failure to control a kick have been developed in more detail. During the drilling of a well, an influx of formation fluids (kick) can occur during any one of the operations listed below (Bercha, 1983):

- Drilling (Event Box A18)
- Circulating (Event Box A21)
- Tripping (Event Boxes A19 and A21)
- Coring (Event Box X32)
- Logging (Event Box X34)
- Casing (Event Box X33)
- Testing (Event Box X31)

Kicks taken during drilling (Event Box A18), circulating (Event Box A21) and tripping (Event Boxes A19 and A20) operations account for more than 90% of all kicks. Only these activities were broken down in more detail. Generally kicks result from:

- insufficient hydrostatic pressure,
- lost circulation,
- swabbing,
- abnormally charged formations, and
- improper use of surface equipment.

Historical data permitting, frequencies of occurrence of basic and undeveloped kick causal events in units of "kicks per well drilled" can be established.

For a site-specific facility analysis (in contrast to a facility analysis based on general statistics), four additional components have been incorporated in the "kick occurs" subtree shown in Figures 4.3a, 4.3b and 4.3c (BPRC, 1986):

- Wellbore integrity (Event Box X25),
- Formation pressure (Event Box X37),
- Data quality (Event Box X10) (drilling information on well to be drilled), and
- Well depth (Event Box X7).

Of these four, wellbore integrity and formation pressure have been identified as direct causes of well control problems (Bercha, 1983). The quality of data on wellbore integrity and formation pressure affects the ability of the drilling crew to avoid well control problems. These factors can be incorporated into the frequency analysis by modifying the events (whose frequency of occurrence is based on general statistics) affected by a factor that has been established by some sort of correlation procedure. One possible method correlates well control problems with the Lahee system which classifies wells according to the level of drilling which has been conducted in the area.

A correlation has been established between well depth and the occurrence of well control problems (BPRC, 1986). The data indicate that as the depth of the well increases, the likelihood of well control problems will also increase. This correlation is used to develop a modifying depth factor M(X7) on a site-specific basis. For a well depth of 3397 m, M(X7) = 1.00. For a deeper well, the factor increases (e.g. for a well depth of 4000 m, M(X7) = 3.3) and for a shallower well, the factor decreases (e.g. for a well depth of 2000 m, M(X7) = 0.54). Details of the calculation procedure are given in Appendix B.

These modifying (or multiplying) factors, when used in the fault tree, adjust the frequency or probability of occurrence of those basic or undeveloped events they are modifying. For example, if the frequency of occurrence of kicks while drilling due to connection swabbing (Event Box X36) based on Alberta historical data (for an average well depth of 3397m) were $2.00 \cdot 10^{-2}$ kicks/well drilled, then for a 2000 m well depth, this frequency would be modified to $1.08 \cdot 10^{-2}$ (Event Box A35: $2.00 \cdot 10^{-2} \cdot 0.54$).

Previous studies did not allow for modification of kick and causal event frequencies nor blowout frequencies to reflect site specific applications.

Controlling a kick (Event Box A5) involves detection (Event Box A6) and effective handling (Event Box A7). While fluid is being circulated and the mud pump is on, several factors can indicate that an influx of formation fluids may have occurred within the borehole. However increase in the mud pit volume (Event Box A9), for example, definitely identifies such a situation. While the mud pump is off (Event Box A10), a flowing well (Event Box A12) and/or a mud pit volume increase (Event Box A13) identify the occurrence of a kick. Failing to detect a kick can be directly attributed to equipment failure (level or flow detector, alarm) (Event Boxes X8 and X9) or operator error (signal ignored, equipment not maintained) (Event Box X6). Failing to detect a kick would also be influenced by depth of the well (Event Box X7).

Ineffective kick handling (Event Boxes A7 and A11) involves two main subevents, failure to shut in the well (Event Box A14) and failure to circulate the kick out (Event Box A15). Both can be attributed to equipment failure (Event Boxes A16 and A17) and improper procedures (Event Boxes X12 and X13). The quality of data (Event Box X10) and inflow potential (Event Box X11) are also felt to be modifying factors for effective kick handling. Inflow potential influences the probability of ineffective kick handling only in the sense that a prolific reservoir will react quickly and strongly to displace wellbore fluid should an underbalanced environment be created in the wellbore. An inflow potential factor can be estimated by correlating the frequency of blows against 0.5*log(actual AOF/normalized AOF), a minor deviation of the suggestion made by the BPRC (1986), thereby allowing estimation of a multiplier that will be used to modify Event Box A11.

3.2.2 Historical Data on Well Control Problems for Drilling Wells

The historical data used for the quantification of the fault tree are presented in Appendix A. The data (1975 - 1988) includes both oil and gas wells and are summarized in Table 3.1. Historical data has been obtained from ERCB records on well control problems (blowouts, blows and kicks) during drilling. The data could not be segregated in sufficient detail to allow detailed quantification of basic and undeveloped fault tree events. As a result, significant portions of the fault tree could not be quantified.

Blowout Frequency

The frequency of occurrence of blowouts (blowouts per well drilled) for sour wells is somewhat higher than for sweet wells ($4.5 \cdot 10^{-4}$ or 1 in 2208 compared to $3.16 \cdot 10^{-4}$ or 1 in 3163). The reason for the difference is the depth to which most sour wells are being drilled. These trends can be observed in Table 3.22 of the ERCB Volume 7. The last five years have shown an increase in deeper sour well drilling. The combined frequency for both sweet and sour wells is $3.34 \cdot 10^{-4}$ blowouts per well drilled (or 1 blowout in 2992 wells drilled). Bercha (1985) estimated the combined frequency to be $3.5 \cdot 10^{-4}$ (1 in 2860). The larger data sample used in this study accounts for the small difference in combined blowout frequency.

Table 3.1

Drilling Well Summary Statistics (1975 - 1988).

Well Control Problem	Sweet	Sour	Total
Blowouts	23	5	28
Blows or blowouts	82	8	90
Kicks, blows or blowouts	___	___	2918
All Wells Drilled	72748*	11037*	83786
Blowout rate	$3.16 \cdot 10^{-4}$ or (1 in 3163)	$4.53 \cdot 10^{-4}$ or (1 in 2207)	$3.34 \cdot 10^{-4}$ or (1 in 2992)

* The split between sweet and sour wells is an estimate based on Figure 3.7 in ERCB, Volume 7.

Kick Frequency

The data base for the drilling blowouts is rather small statistically (5) to work with, so another important statistic looked at was the number of kicks. Recent ERCB work (Wylie 1990) on drilling kick statistics indicated that while the frequency of occurrence of a well blowout was 1 in 2850, the frequency of occurrence of a kick was substantially higher at 1 in 25. Further information was gained when Wylie segregated the data into exploratory and development frequencies of occurrence. For development wells, the blowout frequency was 1 in 4370 with the frequency of a kick at 1 in 32. For exploratory wells, the blowout frequency was 1 in 1580 with the frequency of a kick at 1 in 18. The probability of an exploratory well kick is therefore 1.8 times greater than a development well kick. However, the probability of an exploratory blowout is 2.8 times greater than a development well blowout.

Wylie noticed that the frequency of kicks also increases with depth. For depths of 1000 metres, the kick frequency was 1 in 56, whereas for depths of 4000 metres, it was 1 in 4, or 12 times greater. The greatest number of kicks occurred during the tripping and drilling operations. Wylie also noted that a significant improvement in drilling rig inspection had increased the quality of blowout prevention equipment and crew kick control, but had not reduced the kick frequency.

Development/Exploratory and Well Depth Consideration

Using the information obtained from Wylie, further work was done on the data base for the years 1975 to 1988 (see ERCB Volume 7). To use the fault tree for drilling of development or exploratory wells, the entire set of development well data had to be used. It is based on all wells that had a Lahee classification. There was no split available for fluid type or for sweet and sour blowouts, blows or kicks. The historical frequency of occurrence of a development well blowout was $2.77 \cdot 10^{-4}$ and for an exploratory well was $5.89 \cdot 10^{-4}$. These frequencies are given below:

Frequency of Occurrence	Development	Exploratory	Ratio Dev:Expl
Kick	$3.82 \cdot 10^{-2}$	$5.27 \cdot 10^{-2}$	1:1.4
Blow	$1.03 \cdot 10^{-3}$	$1.52 \cdot 10^{-3}$	1:1.5
Blowout	$2.77 \cdot 10^{-4}$	$5.89 \cdot 10^{-4}$	1:2.1

A kick probability can be expected to be higher for exploratory wells since formations are not as well known. The ~ 30% increase in the Development:Exploratory ratio would not be expected under the assumption that exploratory wells are drilled to the same depth as development wells. The data below indicates that 57% of development wells finished shallower than 1000 m compared with 28% of exploratory wells. Also, 10% of development wells finished deeper than 2000 m while 22% of exploratory wells fall into the same depth range.

Percentage of Wells Drilled for Sweet and Sour Wells

Depth (m)	Exploratory	Development
0 - 999	28%	57%
1000 - 1999	50%	33%
2000 - 2999	17%	9.2%
3000 - 3999	4%	.7%
4000 - 9999	1%	.1%

A further segregation for less than 1000 m and greater than 2000 m is provided.

Occurrence	Kicks		Blows/1000 m		Blowouts/1000 m	
Years	< 1000 m	> 2000 m	< 1000 m	> 2000 m	< 1000 m	> 2000 m
75-86	8.7	39	0.20	0.84	0.09	0.45
78-87	9.6	44	0.20	0.78	0.08	0.36
79-88	9.6	46	0.18	0.50	0.09	0.36

The table above indicates that the frequency of all occurrences is higher at the greater depths. In order to determine whether the difference in kick frequency is a function of drilling experience in developed or exploratory pools or a function of depth, fault trees should be completed for each by depth.

Historical data on the release geometries and flow scenarios identified in the GASCON2 report were available from well blowout reports and are summarized in Table 3.2. Six out of 22 wells had some horizontal flow with only one horizontal jet observed. It was assumed that horizontal jets have an equal chance of being a downwind jet as being an upwind jet. Three blowouts which ejected fluid outside of the borehole were not used to estimate probability of flow scenarios since these blowouts could not be classified according to the flow scenarios presented in the GASCON2 report without skewing the statistics.

Table 3.2

Drilling Well Release Geometry and Flow Scenario Summary Statistics. *

Release Geometry	Number of Observations	Probability P_{G_k}
Downwind Jet	0.5	0.023
Upwind Jet	0.5	0.023
Vertical Jet	13	0.590
Cloud	8	0.364
Total	22	1.000
Flow Scenario	**Number of Observations**	**Probability P_{E_j}**
Casing Flow	1	0.053
Combined Flow	1	0.053
Annular Flow	10	0.526
Drill Pipe Flow	7	0.368
Total	19	1.000

* Taken from Table 4.20, ERCB Volume 7.

3.2.3 Estimation of Release Frequencies for Drilling Wells

For the purpose of demonstrating how the release frequency for a drilling well is estimated, the base case identified in the GASCON2 report will be taken here as an example. This scenario is defined by the following conditions:

- Source Conditions:

  Probability of non-ignition $P_{I_i} = 0.011$

  Probability of downwind jet $P_{E_k} = 0.023$

  Probability of drill pipe flow $P_{E_j} = 0.368$

- Meteorological Conditions:

  Stable Conditions
  Wind Speed (1.0 m/s)
  Surface Heat Flux (-15.0 W/m^2)
  Probability of meteorological conditions $P_{M_l} = 0.0628$

Quantification of the fault tree for this scenario was carried out as far as reliable historical data would permit. The data include well control problems incurred during the drilling operations. Reliable data on kick causal factors were not available. As a result, their frequencies of occurrence could not be quantified, although previous studies had attempted this.

The quantification of the fault tree is shown in Table 3.3. Note that the computed value A2 is equal to the sour well blowout frequency based on historical data.

Well deliverability for a given well is an assumed quantity in this study (See Appendix B, Box X1); therefore emission rate probabilities are treated as being equal to the probability of each flow scenario.

For each input value given in Table 3.3, a qualifying comment has been made regarding the source and reliability of the data. A more detailed description of how values were estimated is given in Appendix B. The frequency of a base case well blowing out during drilling is $2.53 \cdot 10^{-9}$.

Table 3.3

Drilling Fault Tree Event Frequencies (Base Case).

Event Box	Fault Tree Event		Input Values	Computed Values	Source
A1	USGR given E, G and M	F4		$2.53 \cdot 10^{-9}$	
X1	Potential Emission Rate (E)	P	$3.68 \cdot 10^{-1}$		Drill Pipe Flow (Table 4.2)
X2	Potential Geometry (G)	P	$2.30 \cdot 10^{-2}$		Downwind Jet (Table 4.2)
X3	Potential Meteorology (M)	P	$6.28 \cdot 10^{-2}$		Base Case (Section 4.5)
*	USGR	F4		$4.76 \cdot 10^{-6}$	
A46	Non-Ignition	P		$1.05 \cdot 10^{-2}$	
A47	Ignition Failure	P		$5.00 \cdot 10^{-4}$	
X43	Primary Ignition Failure	P	$1.00 \cdot 10^{-2}$		Bercha, 1986
X44	Secondary Ignition Failure	P	$5.00 \cdot 10^{-2}$		Bercha, 1986
X45	Operator Error	P	$1.00 \cdot 10^{-2}$		Henley & Kumamoto
A2	Uncontrolled Well Blowout	F3		$4.53 \cdot 10^{-4}$	
X4	Failure to Control Blow	P	$5.56 \cdot 10^{-2}$		ERCB Volume 7
A3	Blow Occurs	F2		$1.07 \cdot 10^{-3}$	
A5	Failure to Control Kick	P	$3.08 \cdot 10^{-2}$		ERCB Volume 7
A4	Kick Occurs	F1		$3.48 \cdot 10^{-2}$	
A18	Kick while Drilling	F1	$1.48 \cdot 10^{-2}$		ERCB Volume 7
A19	Kick while Tripping Out	F1	$1.19 \cdot 10^{-2}$		ERCB Volume 7
A20	Kick while Tripping In	F1	$3.71 \cdot 10^{-3}$		ERCB Volume 7
A21	Kick while Circulating	F1	$9.79 \cdot 10^{-4}$		ERCB Volume 7
X31	Kick while Testing	F1	$1.06 \cdot 10^{-3}$		ERCB Volume 7
X32	Kick while Coring	F1	$1.31 \cdot 10^{-3}$		ERCB Volume 7
X33	Kick while Running Casing	F1	$6.92 \cdot 10^{-4}$		ERCB Volume 7
X34	Kick while Logging	F1	$2.15 \cdot 10^{-4}$		ERCB Volume 7
X34.5	Other Kicks	F1	$1.31 \cdot 10^{-4}$		ERCB Volume 7

Note: F1 = Frequency (Kicks/Well Drilled)
F2 = Frequency (Blows/Well Drilled)
F3 = Frequency (Blowouts/Well Drilled)
F4 = Frequency (USGR/Well Drilled)
P = Probability
* = Combine (multiply) event A2 and A46 (Not Shown on Fault Tree)
USGR = Uncontrolled Sour Gas (H_2S) Release
• Event box numbers are aligned to show input events shifted to the right of the output event

Table 3.3a provides the frequency estimates for the same base case well and divides the fault tree into development and exploratory wells by depth categories. The data substantiates the earlier comment that the higher frequency of occurrence is in exploratory wells at the largest depths.

Table 3.3a

Drilling Fault Tree Event Frequencies (Base Case) with Depth Consideration.

Event Box	Development Wells 0-1000 m	1000-2000 m	2000-3000 m	3000-4000 m	> 4000 m	TOTAL
USGR A1						$9.38 \cdot 10^{-11}$
Blowout A2						$1.68 \cdot 10^{-5}$
Blow A3	$7.56 \cdot 10^{-4}$	$2.72 \cdot 10^{-3}$	$7.87 \cdot 10^{-3}$	$8.65 \cdot 10^{-2}$	0	$8.24 \cdot 10^{-4}$
Kick A4	$2.80 \cdot 10^{-2}$	$7.15 \cdot 10^{-2}$	$3.06 \cdot 10^{-1}$	3.55	$3.46 \cdot 10^{-1}$	$2.80 \cdot 10^{-2}$
	Exploratory Wells 0-1000 m	1000-2000 m	2000-3000 m	3000-4000 m	> 4000 m	TOTAL
USGR A1						$6.79 \cdot 10^{-10}$
Blowout A2						$1.32 \cdot 10^{-4}$
Blow A3	$1.14 \cdot 10^{-3}$	$1.45 \cdot 10^{-3}$	$6.00 \cdot 10^{-3}$	$1.88 \cdot 10^{-2}$	$8.76 \cdot 10^{-2}$	$1.14 \cdot 10^{-3}$
Kick A4	$3.49 \cdot 10^{-2}$	$5.35 \cdot 10^{-3}$	$1.74 \cdot 10^{-3}$	$6.99 \cdot 10^{-1}$	2.93	$3.49 \cdot 10^{-2}$

3.3 Frequency Analysis for Non-Drilling Wells

3.3.1 Description of Non-Drilling Well Fault Tree

Figure A.2 in Appendix A shows the fault tree developed for non-drilling wells. The fault tree is split into releases during non-servicing and servicing. This then allows for the fault tree to be used for producing or non-producing wells. This section covers the producing well case. The producing category includes flowing, pumping, gas injection and storage wells. (See ERCB Volume 7)

The top event (Event Box A1) is an uncontrolled sour gas release from a non-drilling well for a given emission rate (Event Box X1), release geometry (Event Box X2) and meteorological conditions (Event Box X3). The frequency of occurrence for this event can be estimated knowing the:

- frequency of occurrence of an uncontrolled well blowout F(A2),
- probability of a potential emission rate P(X1),
- probability of a potential release geometry P(X2), and
- probability of a potential meteorological conditions P(X3).

With the exception of the top AND logic gate, the fault tree is essentially identical to the one developed by Bercha (1985), which was felt to have sufficient detail and adequate structure. The fault tree takes into account emission rate, release geometry, meteorology and ignition, thereby allowing well defined events to be specified.

An uncontrolled release of sour gas from producing wells (Event Box A1) could occur during normal production (Event Box A3) or during servicing (Event Box A4). During normal production, a sour gas release can occur either due to operations at the well (Event Box A10) (equipment problems, human error) or due to an external accident (Event Box A11). As a mitigative measure, regulations stipulate that critical sour gas wells must be equipped with a sub-surface safety valve (SSSV) to shut in the well in the event of a failure in the well surface facilities (Event Box A6). SSSV's are installed in the production tubing and would be unable to stop a release through the annulus. Producing sour gas wells under normal operation are unmanned. Should a blowout occur, ignition of the sour gas release is unlikely.

Servicing operations (Event Box A4) include wireline work (Event Box A8) (minor operation) and workovers (Event Box A9) (major operation). Failure causes for each operation can again be classified into human error (Event Boxes A15 and X17), equipment failure (Event Box X18 and X19) and external accidents (Event Box X20). Should a blowout occur, service crews can immediately ignite the release with shotgun flares. The probability of non-ignition (Event Box A14) would be small and would be dependent on igniter failure (Event Box X23) or operator error (Event Box X24). Blowout frequency should be expressed as blowouts per service operation, thus requiring conditional events for frequency of service operation to obtain frequency per well•year. That is:

$$\left\{\frac{\text{blowouts}}{\text{operation}}\right\} \cdot \left\{\frac{\text{operations}}{\text{well} \cdot \text{year}}\right\} = \left\{\frac{\text{blowouts}}{\text{well} \cdot \text{year}}\right\}$$

3.3.2 Description of Non-Drilling, Non-Producing Well Fault Tree

Figure A.2 in Appendix A shows the fault tree developed for non-drilling wells and as mentioned in Section 3.3.1, it can be used for non-producing as well. The only difference in this section is that the blowout statistics and numbers of wells in the fault tree are for non-drilling, non-producing wells including suspended, capped and standing gas wells. (See ERCB Volume 7)

3.3.3 Historical Data on Well Blowouts for Non-Drilling Wells

The number of blowouts for non-drilling wells were split equally between producing and non-producing wells, and this analysis included both. Historical data within ERCB data records were sufficiently segregated to allow quantification of basic and undeveloped fault tree events. Blowout (or release, Boxes A6 and A5 in the fault tree) occurrence data and well count for producing sour and sweet gas wells are presented in Appendix A and are summarized in Table 3.4. The frequency of a producing blowout occurrence was higher for sour gas wells ($3.9 \cdot 10^{-4}$ blowouts/(well•year) or 1 in 2541) than for sweet gas wells ($1.13 \cdot 10^{-4}$ or 1 in 8784). The combined frequency was $1.31 \cdot 10^{-4}$ (or 1 in 7635). The non-producing numbers are the same for sour service. As a result, sour gas well data were used in this study, whereas in the drilling case both sweet and sour data had to be used.

Note that not all blowouts as defined here necessarily lead to an uncontrolled sour gas release.

Table 3.4

Non-Drilling Well Summary Statistics (1976-1988).

	Sweet	Sour	Total
Blowouts (Producing)	31	7	38
Blowouts (Non-Producing)	37	7	44
Well•years of Service (Producing)	272 325	17 788	290 113
Well•years of Service (Non-Producing)		45 461	
Blowout Rate (Producing)	$1.14 \cdot 10^{-4}$	$3.94 \cdot 10^{-4}$	$1.30 \cdot 10^{-4}$
Blowout Rate (Non-Producing)*		$1.54 \cdot 10^{-4}$	

* Estimated non-producing records are not as detailed as producing.

Historical data pertaining to causal factors are also presented in Appendix A. The data were classified into the following causal groupings:

- Equipment failure,
- Incorrect procedures,
- Environmental accident, and
- Third party.

Total non-drilling gas well causal data (which include data for producing wells) were used to synthesize frequency of occurrence values for producing gas well (See Appendix C1 for details). Similar data appears in Appendix C2 for the non-drilling, non-producing case.

Historical data for servicing occurrences were not segregated between wireline operations and workovers. In addition, the total number of servicing operations was not available within ERCB data records. Their frequency of occurrence, thus could not be estimated in units of blowouts/service operation, but was estimated in units of blowouts/(well•year). Therefore, for a site specific assessment, the estimated frequency of occurrence during servicing would be independent of the frequency of servicing operations. Bercha (1986) has attempted to use this method.

ERCB data for producing well blowouts did not contain observed release geometry. The estimated probabilities are based on the assumptions described in Appendix A and are presented in Table 3.5.

3.3.4 Estimation of Release Frequencies for Non-Drilling Wells

Tables 3.6 (a) and 3.6 (b) shows the input and computed fault tree event values for the non-drilling well fault tree using producing and non-producing sour gas well data for the base case scenario described in Section 3.3. Qualifying comments have been made in Table 3.5 regarding source and reliability of the data. Some quantification of ERCB data was performed in order to define basic and undeveloped fault tree events. Details are provided in Appendix C.

The base case frequency for producing wells (Table 3.6 a) was $1.32 \cdot 10^{-7}$ and for non-producing wells (Table 3.6 b) was $2.20 \cdot 10^{-8}$. Producing blowouts are predicted to occur almost 4 times more often than non-producing with both frequencies being larger than drilling wells at $2.53 \cdot 10^{-9}$.

Table 3.5

Non-Drilling Well Release Geometry and Flow Scenario Summary Statistics.

Producing	
Release Geometry	Probability P_{G_k}
Downwind Jet	0.25
Upwind Jet	0.25
Vertical Jet	0.50
Cloud	0.0
Total	1.00
Flow Scenario	Probability P_{E_j}
Casing Flow	0.171
Combined Flow	0.171
Annular Flow	0.171
Tubing Flow	0.487
Total	1.00

Non-producing	
Release Geometry	Probability P_{G_k}
Downwind Jet	0.25
Upwind Jet	0.25
Vertical Jet	0.50
Cloud	0
Total	1.00
Flow Scenario	Probability P_{E_j}
Casing Flow	0.33
Combined Flow	0.33
Annular Flow	0
Tubing Flow	0.33
Total	1.00

Table 3.6 a

Non-Drilling Producing Fault Tree Event Values (Base Case).

Event Box	Fault Tree Event		Input Values	Computed Values	Source
A1	USGR for given E, G and M	F		$1.32 \cdot 10^{-7}$	
X1	Potential Emission Rate (E)	P	$4.87 \cdot 10^{-1}$		Tubing Flow
X2	Potential Geometry (G)	P	$2.50 \cdot 10^{-1}$		Downwind Jet
X3	Potential Meteorology (M)	P	$6.28 \cdot 10^{-2}$		Base Case
A2	USGR	F		$1.73 \cdot 10^{-5}$	
A3	USGR during NP	F		$3.55 \cdot 10^{-6}$	
X4	Non-Ignition during NP	P	1.00		Assumed Value
A6	Release from Well	F		$1.36 \cdot 10^{-4}$	
A10	Operations at Well	F		$1.24 \cdot 10^{-4}$	
X5	Corrosion	F	$3.80 \cdot 10^{-5}$		ERCB Volume 7
X6	Equipment Failure	F	$1.52 \cdot 10^{-5}$		ERCB Volume 7
A13	Human Error	F		$7.10 \cdot 10^{-5}$	
X7	Incorrect Procedures	F	$6.42 \cdot 10^{-5}$		ERCB Volume 7
X8	Incorrect Maintenance	F	$6.76 \cdot 10^{-6}$		ERCB Volume 7
A11	External Accident	F		$1.19 \cdot 10^{-5}$	
X9	Third Party Damage	F	$8.88 \cdot 10^{-6}$		ERCB Volume 7
X10	Environmental Accident	F	$3.03 \cdot 10^{-6}$		ERCB Volume 7
A7	Failure to Control Release	P		$2.61 \cdot 10^{-2}$	
X11	Operator Error	P	$1.00 \cdot 10^{-2}$		Henley & Kumamoto
A12	SSSV Unavailable	P		$1.61 \cdot 10^{-2}$	
X12	SSSV Failure	P	$3.50 \cdot 10^{-3}$		
X13	Incorrect SSSV Setting	P	$1.00 \cdot 10^{-2}$		
X14	SSSV Control System Failure	P	$2.60 \cdot 10^{-3}$		
A4	USGR during Servicing	F		$1.37 \cdot 10^{-5}$	
A14	Non-Ignition during Servicing	P		$5.10 \cdot 10^{-2}$	
X23	Igniter Failure	P	$5.00 \cdot 10^{-2}$		Bercha, 1986
X24	Operator Error	P	$1.00 \cdot 10^{-3}$		Bercha, 1986
A5	Release during Servicing	F	$2.69 \cdot 10^{-4}$		ERCB Supplement

Note: F = Frequency (Number/(well•year))
P = Probability
NP = Normal Production
USGR = Uncontrolled Sour Gas (H_2S) Release
SSSV = Subsurface Safety Valve

Table 3.6 (b)

Non-Drilling Non-Producing Fault Tree Event Values (Base Case).

Event Box	Fault Tree Event		Input Values	Computed Values	Source
A1	USGR for given E, G and M	F		$2.20 \cdot 10^{-8}$	
X1	Potential Emission Rate (E)	P	$3.40 \cdot 10^{-1}$		Tubing Flow
X2	Potential Geometry (G)	P	$2.50 \cdot 10^{-1}$		Downwind Jet
X3	Potential Meteorology (M)	P	$6.28 \cdot 10^{-2}$		Base Case
A2	USGR	F		$4.12 \cdot 10^{-6}$	
A3	USGR during NP	F		$4.83 \cdot 10^{-6}$	
X4	Non-Ignition during NP	P	1.00		Assumed Value
A6	Release from Well	F		$1.58 \cdot 10^{-4}$	
A10	Operations at Well	F		$1.32 \cdot 10^{-4}$	
X5	Corrosion	F	$7.86 \cdot 10^{-5}$		ERCB Volume 7
X6	Equipment Failure	F	$3.14 \cdot 10^{-5}$		ERCB Volume 7
A13	Human Error	F		$2.20 \cdot 10^{-5}$	
X7	Incorrect Procedures	F	$1.99 \cdot 10^{-5}$		ERCB Volume 7
X8	Incorrect Maintenance	F	$2.09 \cdot 10^{-6}$		ERCB Volume 7
A11	External Accident	F		$2.58 \cdot 10^{-5}$	
X9	Third Party Damage	F	$2.20 \cdot 10^{-5}$		ERCB Volume 7
X10	Environmental Accident	F	$3.76 \cdot 10^{-6}$		ERCB Volume 7
A7	Failure to Control Release	P		$2.61 \cdot 10^{-2}$	
X11	Operator Error	P	$1.00 \cdot 10^{-2}$		Henley & Kumamoto
A12	SSSV Unavailable	P		$1.61 \cdot 10^{-2}$	
X12	SSSV Failure	P	$3.50 \cdot 10^{-3}$		
X13	Incorrect SSSV Setting	P	$1.00 \cdot 10^{-2}$		
X14	SSSV Control System Failure	P	$2.60 \cdot 10^{-3}$		

3.3.5 Inspection Frequency Consideration

As discussed previously, SSSV unavailability (the probability that the subsurface safety value will not operate when demanded) is dependent on the time interval between inspection. For this study, a time period of two months was used. The relationship for fractional down time is given by Equation 3.4. Table 3.7 shows how inspection time for SSSV affects the frequency of occurrence of an uncontrolled sour gas release (F(A2)). Previous studies have not considered the quantitative implications of the inspection interval. This can be an important consideration in terms of risk reduction.

Table 3.7

SSSV Inspection Interval Effect on Release Frequency.

Inspection Interval (Months)	F(A2) (USGR/(well•year))		Percent Change
0.5	$1.23 \cdot 10^{-5}$	(1 in 81 300)	-26%
1.0	$1.40 \cdot 10^{-5}$	(1 in 71 428)	-19%
2.0 (Base Case)	$1.73 \cdot 10^{-5}$	(1 in 57 803)	-
6.0	$3.04 \cdot 10^{-5}$	(1 in 32 894)	+76%

USGR = Uncontrolled Sour Gas (H_2S) Release

3.4 Pipeline Analysis

3.4.1 Description of Pipeline Fault Tree - Ruptures

Figure A.3 in Appendix A shows the fault tree developed for sour gas pipeline ruptures. The top event (Event Box A1) is an uncontrolled H_2S release from a pipeline rupture (Event Box A2) for a given emission rate (Event Box A3), release geometry (Event Box X1) and meteorological conditions (Event Box X2). The frequency of occurrence for this event can be estimated knowing:

- the frequency of occurrence of a sour gas pipeline rupture F(A2),
- the probability of a potential emission rate P(A3),
- the probability of a potential geometry P(X1), and
- the probability of a potential meteorology P(X2).

Sour gas pipeline ruptures have been grouped according to those occurring in buried pipe (A7) and those occurring in surface equipment (A8). This approach had also been taken by Bercha (1985) and allows the relative risk of surface installations to be addressed. However, the structure of the fault tree developed here is different from Bercha, and reflects failure causes identified by the ERCB (1983). Following the above classification of pipeline ruptures, possible flow scenarios were presented in Phase I. Four rupture locations were identified, each corresponding to a flow scenario:

- *End Pipe Rupture*. Rupture of a surface pipe adjacent to an ESD valve which will deplete one pipeline segment, all ESD valves operate as designed.

- *ESD Valve Failure*. Rupture at an ESD valve which will deplete two pipeline segments if ESD valve is not coupled with a check valve or check valve fails to stop reverse flow of fluids, all other ESD valves operate as designed.

- *Center Pipe Rupture*. Rupture of buried pipe between two mainline ESD valves which will deplete one pipeline segment, all ESD valves operate as designed.

- *Decay to Steady State*. Rupture of buried pipe between the wellhead ESD or SSSV valve and a mainline ESD valve, wellhead ESD valve fails, the SSSV does not close, all other ESD valves operate as designed.

In the frequency analysis, surface pipe and surface installations (i.e. ESD valves, check valves, etc.) were grouped into the category of surface equipment.

For a typical pipeline system that may contain one or more mainline emergency shutdown (ESD) valves and check valves (non-return valves usually coupled with ESD valves), the emission rate profile following a rupture will depend on the size of the hole and whether ESD and check valves operate successfully. All these factors are considered toward calculating the probability of a potential emission rate.

3.4.2 Description of Pipeline Fault Tree - Leaks

Figure A.3 shows the fault tree developed for sour gas pipeline ruptures. If you assume that the same fault tree can be used to arrive at a frequency for leaks, the leak statistics can be substituted directly. This substitution is not totally valid for all categories, however closely approximates the rupture situation and is therefore useful for comparison purposes. The top event (Event Box A1) is then an uncontrolled H_2S release from a pipeline leak (Event Box A2) for a given emission rate (Event Box A3), release geometry (Event Box X1) and meteorological conditions (Event Box X2). The frequency of occurrence for this event can be estimated knowing:

- the frequency of occurrence of a sour gas pipeline leak F(A2),
- the probability of a potential emission rate P(A3),
- the probability of a potential geometry P(X1), and
- the probability of a potential meteorology P(X2).

Sour gas pipeline ruptures have been grouped according to those occurring in buried pipe (A7) and those occurring in surface equipment (A8). This approach had also been taken by Bercha (1985) and allows the relative risk of surface installations to be addressed. However, the structure of the fault tree developed here is different from Bercha, and reflects failure causes identified by the ERCB (1983). Following the above classification for pipeline ruptures was not possible for leaks. All leak data were assumed to occur in buried pipe. Only one leak location was identified corresponding to a flow scenario:

- *Center Pipe Leak.* Leak of buried pipe between two mainline ESD valves which will deplete contents of the pipeline, all ESD valves operate as designed.

In the frequency analysis, surface pipe and surface installations (i.e. ESD valves, check valves, etc.) were grouped into the category of surface equipment.

For a typical pipeline system that may contain one or more mainline emergency shutdown (ESD) valves and check valves (non-return valves usually coupled with ESD valves), the emission rate profile following a leak will depend on the size of the hole and whether ESD and check valves operate successfully. All these factors are considered toward calculating the probability of a potential emission rate.

3.4.3 Historical Data For Pipeline Ruptures and Leaks

Ruptures

Historical data on pipeline ruptures within ERCB data records were sufficiently segregated to allow the quantification of most basic and undeveloped events. The data used in this study are presented in Table A.5, Appendix A. A total of 5500 km of pipeline was in sour gas service in 1989, transporting sour gas (with H_2S contents greater than 1%). This is a total of 47500 km•years of sour gas service for the period 1975 to 1989.

A total of 40 sour gas pipeline ruptures were observed over that time period, each attributed to a causal factor. A review of the individual reports allowed the allocation of ruptures into the buried pipe and surface equipment categories. In addition, this review indicated that three ruptures in 1979 due to pipe failure occurred in spiral welded pipe. Since this type of pipe is no longer used in sour gas service in Alberta, these failures were deleted from the database. Failures during testing or construction were also excluded. These exclusions brought the total down from 40 to 31 ruptures, for this study.

Data on observed hole size were available for only seven of the nine ruptures shown in Appendix A for the years 1985 to 1989. Release geometries for ruptures were categorized in Phase I as:

- *Long Rupture.* The escaping gas is released through two openings, each opening with an area equal to the cross sectional area of the pipe. Defined here as a 100% rupture.
- *Short (or Partial) Rupture.* The escaping gas is released through one opening whose area is equal to the cross sectional area of the pipe. Defined as a 50% rupture.

Of the nine ruptures, one was observed to be a long rupture (1/9 = 0.11). The remaining six short ruptures had an average opening area of 32% (8/9 = 0.89) (based on ERCB classification).

No data were available from the ERCB regarding release geometry. As a consequence, for releases from buried pipe, the rupture was assumed to occur at the bottom of the pipe resulting in a cloud release. For surface ruptures, the geometry was assumed to be a horizontal jet.

Historical pipeline data used in this study are specifically related to the sour gas pipeline network. Previous studies did not have this detailed level of data and were forced to use combined sweet and sour data. In addition, this study treats the release scenario in a more rigorous fashion.

Leaks

Historical data on leaks are presented in Table A.8, Appendix A. There were a total of 245 leaks over the same time period (1975 to 1989). The leak rate is approximately 8 times that of the rupture rate. A short rupture was used instead of the long rupture.

3.4.4 Estimation of Rupture Frequencies for Pipelines

A listing of fault tree event frequencies and probabilities for pipeline occurrences is shown in Table 3.8. As before, the base case meteorological conditions have been used as an example to quantify the probability of potential meteorological conditions.

Additional failure causes identified in the fault tree for which no historical data were available were analysed. Their probability of occurrence, although relatively small, is non-zero. For these events, frequencies were synthesized based on procedures described in Appendix D. The estimation of these values are judgement calls (guessed values) and are incorporated in the analysis to ensure conservative estimates.

Within Table 3.8, values for the top event (Event Box A1) and probability of potential emission rate are not shown. Frequencies for the top event for each flow scenario are given in Table 3.9.

The rupture location for a pipeline is not fixed as it is in the case of well blowouts. The location of a rupture is an important contributing factor to the emission rate profile. The four flow scenarios that have been identified and described in Section 3.4.1 cover a range of potential emission rate profiles. Each scenario requires that certain valves operate, fail to operate or even rupture. This will affect the probability of potential emission rate, which will be unique for each flow scenario (see Appendix D). Furthermore, some release scenarios represent surface releases while others represent subsurface releases. The frequencies of occurrence of surface and subsurface releases are different and must be estimated from the applicable basic and undeveloped event frequencies listed in Table 3.8. The hole size used to compute probability of potential emission rate in Table 3.8 is based on a long rupture, which is assumed to have a probability of occurrence, P(X4) = 0.11 (i.e. 1 out of 9 observations). The release geometry probabilities are: 1.0 for cloud release from buried pipe ruptures and 0.5 for horizontal downwind jet release (equal chance of jet being upwind or downwind) from surface ruptures.

The frequency of a sour gas rupture (Table 3.10) depends on flow scenarios. The largest frequency was for the centre pipe rupture at $4.13 \cdot 10^{-6}$.

3.4.5 Estimation of Leak Frequencies for Pipelines

While the pipeline rupture fault tree is not suited to be directly used for determining the frequency of a release from a leak, for purposes of comparison the leak statistics have been substituted in the place of the rupture statistics. The frequency of a sour gas leak is $1.48 \cdot 10^{-4}$ which is significantly higher than for the rupture case.

Table 3.8

Pipeline Fault Tree Event Values (Base Case for Ruptures).

Event Box	Fault Tree		Input Values	Computed Values	Comments
A1	USGR for given E, G and M	F1			See Table 3.10
X1	Potential Geometry (G)	P			See Table 3.10
X2	Potential Meteorology (M)	P			See Table 3.10
A3	Potential Emission Rate (E)	P			See Table 3.10
X4	Potential Hole Size	P	$1.10 \cdot 10^{-1}$		
A5	ESD Valve Unavailable	P		$1.17 \cdot 10^{-2}$	
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		Assumed Value
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		Computed (Bercha, 1986)
A6	ESD Valve Failure	P	$9.17 \cdot 10^{-3}$		Henley & Kumamoto (1981)
A25	Check Valve Unavailable	P		$5.65 \cdot 10^{-3}$	
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		Assumed Value
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		Computed (Bercha, 1986)
X41	Check Valve Failure	P	$3.08 \cdot 10^{-3}$		Lees (1980)
A2	USGR	F1		$7.45 \cdot 10^{-4}$	
X3	Non-Ignition	P	1.00		Assumed Value
A4	Sour Gas Pipeline Rupture	F1		$7.45 \cdot 10^{-4}$	
X5	Misc./Other Ruptures	F1	$2.11 \cdot 10^{-5}$		ERCB Volume 7
A7	Rupture of Buried Pipe	F1		$6.37 \cdot 10^{-4}$	
A9	Corrosion	F1		$2.03 \cdot 10^{-4}$	
A17	Internal Corrosion	F1	$1.27 \cdot 10^{-4}$		ERCB Volume 7
A20	External Corrosion	F1	$6.33 \cdot 10^{-5}$		ERCB Volume 7
X10	Inadequate Pipe Material	F1	$2.11 \cdot 10^{-6}$		Assumed Value
X11	Corrosion at Girth/Fillet Weld	F1	$1.05 \cdot 10^{-5}$		Assumed Value
A10	External forces	F1		$1.16 \cdot 10^{-4}$	
X19	Earth Movement	F1			ERCB Volume 7
X20	Third Party Damage	F1	$1.05 \cdot 10^{-5}$		ERCB Volume 7
X21	Construction Damage	F1	$6.33 \cdot 10^{-5}$		ERCB Volume 7
A11	Operation Induced Failures	F1	$4.22 \cdot 10^{-5}$	$6.33 \cdot 10^{-4}$	
X22	Overpressure	F1			ERCB Volume 7
X23	Operator Error	F1	$4.22 \cdot 10^{-5}$		ERCB Volume 7
A12	Equipment Failures	F1	u.d.	$2.55 \cdot 10^{-4}$	
X24	Weld Failure	F1			ERCB Volume 7
A22	Pipe Failure	F1	$2.11 \cdot 10^{-5}$	$2.11 \cdot 10^{-4}$	
X25	Excessive Stresses	F1			ERCB Volume 7
X26	Wrong Material	F1	$1.90 \cdot 10^{-4}$ $1.98 \cdot 10^{-6}$		Assumed Value
A8	Rupture of Surface Equip.	F2		$8.12 \cdot 10^{-5}$	
A13	Corrosion	F2		$8.87 \cdot 10^{-6}$	
X27	Internal Corrosion	F2	$5.92 \cdot 10^{-6}$		Assumed Value
X28	External Corrosion	F2	$2.96 \cdot 10^{-6}$		Assumed Value
A14	External forces	F2		$5.42 \cdot 10^{-6}$	
X29	Construction Damage	F2	$1.97 \cdot 10^{-6}$		Assumed Value
X30	Third Party Damage	F2	$4.44 \cdot 10^{-6}$		Assumed Value
X31	Earth Movement	F2	$4.93 \cdot 10^{-7}$		Assumed Value
A15	Equipment Failure	F2		$6.40 \cdot 10^{-5}$	
X32	Failure of an Installation	F2	$9.86 \cdot 10^{-6}$		Assumed Value
X33	Weld failure	F2	$1.97 \cdot 10^{-6}$		Assumed Value
A23	Valve/Fitting Failure	F2	$4.22 \cdot 10^{-5}$		Table A.5
A24	Pipe Failure	F2		$9.95 \cdot 10^{-6}$	
X37	Wrong Material	F2	$9.27 \cdot 10^{-8}$		Assumed Value
X38	Excessive Stresses	F2	$9.86 \cdot 10^{-6}$		Assumed Value
A16	Operation Induced Failures	F2		$2.96 \cdot 10^{-6}$	
X39	Operator Error	F2	$9.86 \cdot 10^{-7}$		Assumed Value
X40	Overpressure	F2	$1.97 \cdot 10^{-6}$		Assumed Value

Notes:
- F1 = Frequency (Number/(km•year))
  F2 = Frequency (Number/(SE•year))
  P = Probability
- To quantify Event A4, P(A8) must be multiplied by 1.07 SE/km
- SE = Surface Equipment
  USGR = Uncontrolled Sour Gas (H_2S) Release
  ESD Valve = Emergency Shutdown Valve
- Event Box numbers are aligned to show input events shifted to the right of the output event.
- u.d. = undefined

Table 3.9

Pipeline Fault Tree Event Values (Base Case for Leaks).

Event Box	Fault Tree		Input Values	Computed Values	Comments
A1	USGR for given E, G and M	F1			See Table 3.10
X1	Potential Geometry (G)	P			See Table 3.10
X2	Potential Meteorology (M)	P			See Table 3.10
A3	Potential Emission Rate (E)	P			See Table 3.10
X4	Potential Hole Size	P	$8.90 \cdot 10^{-1}$		
A5	ESD Valve Unavailable	P		$1.17 \cdot 10^{-2}$	
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		Assumed Value
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		Computed (Bercha, 1986)
A6	ESD Valve Failure	P	$9.17 \cdot 10^{-3}$		Henley & Kumamoto (1981)
A25	Check Valve Unavailable	P		$5.65 \cdot 10^{-3}$	
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		Assumed Value
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		Computed (Bercha, 1986)
X41	Check Valve Failure	P	$3.08 \cdot 10^{-3}$		Lees (1980)
A2	USGR	F1		$5.42 \cdot 10^{-3}$	
X3	Non-Ignition	P	1.00		Assumed Value
A4	Sour Gas Pipeline Rupture	F1		$5.42 \cdot 10^{-3}$	
X5	Misc./Other Ruptures	F1	$1.05 \cdot 10^{-4}$		ERCB Volume 7
A7	Rupture of Buried Pipe	F1		$5.00 \cdot 10^{-3}$	
A9	Corrosion	F1		$4.09 \cdot 10^{-3}$	
A17	Internal Corrosion	F1	$2.85 \cdot 10^{-3}$		ERCB Volume 7
A20	External Corrosion	F1	$1.22 \cdot 10^{-3}$		ERCB Volume 7
X10	Inadequate Pipe Material	F1	$2.11 \cdot 10^{-6}$		Assumed Value
X11	Corrosion at Girth/Fillet Weld	F1	$2.11 \cdot 10^{-5}$		Assumed Value
A10	External forces	F1		$1.27 \cdot 10^{-4}$	
X19	Earth Movement	F1			ERCB Volume 7
X20	Third Party Damage	F1	$4.22 \cdot 10^{-5}$		ERCB Volume 7
X21	Construction Damage	F1	$2.11 \cdot 10^{-5}$		ERCB Volume 7
A11	Operation Induced Failures	F1	$6.33 \cdot 10^{-5}$	0.0	
X22	Overpressure	F1			ERCB Volume 7
X23	Operator Error	F1	0.0		ERCB Volume 7
A12	Equipment Failures	F1	u.d.	$7.83 \cdot 10^{-4}$	
X24	Weld Failure	F1			ERCB Volume 7
A22	Pipe Failure	F1	$3.80 \cdot 10^{-4}$	$4.03 \cdot 10^{-4}$	
X25	Excessive Stresses	F1			ERCB Volume 7
X26	Wrong Material	F1	$4.01 \cdot 10^{-4}$ $1.98 \cdot 10^{-6}$		Assumed Value
A8	Rupture of Surface Equip.	F2		$2.95 \cdot 10^{-4}$	
A13	Corrosion	F2		$1.90 \cdot 10^{-4}$	
X27	Internal Corrosion	F2	$1.33 \cdot 10^{-4}$		Assumed Value
X28	External Corrosion	F2	$5.72 \cdot 10^{-5}$		Assumed Value
A14	External forces	F2		$5.92 \cdot 10^{-6}$	
X29	Construction Damage	F2	$2.96 \cdot 10^{-6}$		Assumed Value
X30	Third Party Damage	F2	$9.86 \cdot 10^{-7}$		Assumed Value
X31	Earth Movement	F2	$1.97 \cdot 10^{-6}$		Assumed Value
A15	Equipment Failure	F2		$9.85 \cdot 10^{-6}$	
X32	Failure of an Installation	F2	$1.97 \cdot 10^{-5}$		Assumed Value
X33	Weld failure	F2	$1.77 \cdot 10^{-5}$		Assumed Value
A23	Valve/Fitting Failure	F2	$4.22 \cdot 10^{-5}$		Table A.5
A24	Pipe Failure	F2		$1.88 \cdot 10^{-5}$	
X37	Wrong Material	F2	$9.27 \cdot 10^{-8}$		Assumed Value
X38	Excessive Stresses	F2	$1.87 \cdot 10^{-5}$		Assumed Value
A16	Operation Induced Failures	F2		0.0	
X39	Operator Error	F2	0.0		Assumed Value
X40	Overpressure	F2	0.0		Assumed Value

Notes:
- F1 = Frequency (Number/(km•year))
  F2 = Frequency (Number/(SE•year))
  P = Probability
- To quantify Event A4, P(A8) must be multiplied by 1.07 SE/km
- SE = Surface Equipment
  USGR = Uncontrolled Sour Gas (H_2S) Release
  ESD Valve = Emergency Shutdown Valve
- Event Box numbers are aligned to show input events shifted to the right of the output event.
- u.d. = undefined

Table 3.10

Frequency of Occurrence Values For Flow Scenarios (Base Rupture and Leak Case).

Rupture Flow Scenario	Frequency of Sour Gas Release F(A2) (Number/(km•year))	Probability of Potential Emission Rate (E) P(A3)	Probability of Potential Geometry (G) P(X1)	Probability of Potential Meteorology (M) P(X2)	Frequency of Sour Gas Release with (E, G, M) F(A1) (Number/(km•year))
1 End Pipe Rupture	$1.08 \cdot 10^{-4}$	$1.07 \cdot 10^{-1}$	0.5	0.0628	$3.63 \cdot 10^{-7}$
2 ESD Valve Rupture	$1.08 \cdot 10^{-4}$	$6.07 \cdot 10^{-4}$	0.5	0.0628	$2.00 \cdot 10^{-9}$
3 Centre Pipe Rupture	$6.58 \cdot 10^{-4}$	$1.07 \cdot 10^{-1}$	1.0	0.0628	$4.42 \cdot 10^{-6}$
4 Decay to Steady State	$6.58 \cdot 10^{-4}$	$1.28 \cdot 10^{-3}$	1.0	0.0628	$5.30 \cdot 10^{-8}$
Leak Flow Scenario	**F(A2) (Number/(km•year))**	**P(A3)**	**P(X1)**	**P(X2)**	**F(A1) (Number/(km•year))**
3 Centre Pipe Leak	$5.42 \cdot 10^{-3}$	$8.69 \cdot 10^{-1}$	$5.00 \cdot 10^{-1}$	$6.28 \cdot 10^{-2}$	$1.48 \cdot 10^{-4}$

Note: • For Flow Scenarios 1 and 2, all input values under box A7 are 0.0, miscellaneous ruptures (F(X5)) combined with surface equipment ruptures.
- For Flow Scenarios 3 and 4, all input values under box A8 are 0.0, buried pipe ruptures (F(A7)).
- For Flow Scenarios 1 and 2, F(A2) in the above table is obtained by multiplying F(A8) in Table 3.8 by the SE density (1.07 SE/km) and assuming an equal chance between a surface pipe rupture (Scenario 1) and a surface valve rupture (Scenario 2)

3.5 Meteorology

As discussed in the GASCON2 report, meteorology is perhaps the most important parameter in the determination of the downwind H_2S concentration profile and hence the consequences for a sour gas release. In the estimation of risk, the consequences of an event at a given point downwind are combined with its frequency of occurrence, which includes the probability of a potential meteorological condition occurring at the time of that event. The meteorological parameters of interest in this study are:

- wind direction (θ),
- wind speed (U_{REF}),
- atmospheric stability (Unstable, Neutral, Stable),
- mixed layer height (Z_i) for unstable atmospheres, and
- surface heat flux (H_O) for stable and unstable atmospheres.

Each parameter has a wide range of potential values, providing a large number of permutations, each with an extremely small probability.

For risk analysis purposes, it is desirable to consider a small number of representative classes of each parameter and the joint probability of the parameters which define the class. For neutral atmospheres, wind direction and wind speed are the independent parameters of concern. For stable atmospheres, surface heat flux needs to be added. For unstable atmospheres, surface heat flux and mixing height need to be added. The range of each parameter class can be adjusted to achieve the desired level of detail.

Joint probabilities of meteorological parameters are computed from the statistical processing of historical weather data obtained from weather station representative of the site in question. As was done in Phase I, meteorological observations from Calgary International Airport were used here for the purposes of illustration. A joint probability analysis was performed on five years (1980 to 1984) of hourly meteorological data using the meteorological preprocessor developed for GASCON2.

Appendix E presents limited joint frequency distributions for the Calgary International Airport meteorological data. Based on this data, the base case meteorological conditions (Stable atmospheres, wind speeds less that 1 m/s) are expected to occur 6.28% of the time. For the purposes of illustration this value includes all wind direction (θ) and surface heat flux (H_O) values. Additional work can be done on persistence and duration, this has not been completed.

3.6 Sensitivity to Uncertainties in Data

The purpose of the sensitivity analysis is to establish the effect errors in estimated base event frequencies would have on the frequency of occurrence of the top event. The effects have been estimated by assigning conservative estimates of high and low values for each base event and calculating the changes in the estimation of the top event frequency for each set of estimates. This procedure establishes an envelope for the expected frequency of the top event.

In risk analyses, two results are usually considered significantly different only if they differ by orders of magnitude (i.e. by factors of 10, 100, 1000, *etc.*). The reason for this being the degree of uncertainty in the numbers that are calculated. This reasoning has been accepted in the interpretation of this sensitivity analysis. By using upper and lower estimates, order of magnitude differences were estimated, thereby establishing a level of confidence in the calculated frequency of occurrence values. It is important to point out that a parameter specific uncertainty analysis is useful when evaluating the effects of mitigative measures. This type of analysis will identify those factors which influence risk most strongly.

Tables 3.3, 3.6a, 3.6b, 3.8 and and 3.9 provide qualifying statements regarding the nature of the data used to quantify the base event. Three general types of data were used:

- ERCB data,
- assumed value based on other studies or literature material, and
- judgement value.

The degree of confidence is highest for ERCB data and lowest for guessed values. Based on this relative degree of confidence, basic event values were adjusted upward and downward by percentages outlined in Appendix F. These adjustments are judgmental in nature, but are felt to be conservative enough to cover the expected range for the basic event values. For values where there was high uncertainty, values of up to ±1000% were used to estimate the conservative frequencies. For ERCB data, the percentage change applied was related to the number of observations in the data set as shown in Table 3.11.

Table 3.11

Percentage Change Assumed for the ERCB Data in the Sensitivity Analysis.

Number Of Observations	% Increase	% Decrease
Less than 10	+ 100	- 50
10 to 50	+ 50	- 25
More than 50	+ 25	- 25

The table compares the base frequencies estimated in Tables 3.3, 3.6a, 3.6b, 3.8 and and 3.9 with the high frequency estimates (all basic event values increased) and low frequency estimates (all basic event values decreased).

The results of the sensitivity analysis are shown in Table 3.12. The table also serves as a summary for the base frequency of occurrence for each sour gas system. All values in the table refer to an uncontrolled sour gas release for a given emission rate, geometry and meteorological condition. The greatest variation in the estimated frequencies is associated with uncontrolled releases from wells. For producing wells and pipelines, the range is about one order of magnitude while for drilling wells the range is about two orders of magnitude. The latter is due to the large assumed variation in ignition probability and the multiplicative effect of primary and secondary ignition. For pipelines the greatest range occurs for the centre pipe rupture scenario, which is about two orders of magnitude. Details are provided in Appendix F. Generally the frequency analysis indicates that the base frequency ranges from 1 in 250 thousand to 1 in 500 million.

Table 3.12

Frequency Analysis Results.

System	Description	Units	Base Frequency	High Estimate	Low Estimate
Drilling Well	Base Case (Drill Pipe Flow)	Number/Well Drilled	$2.53 \cdot 10^{-9}$ (1 in 370 million)	$1.16 \cdot 10^{-7}$ (1 in 8.6 million)	$5.20 \cdot 10^{-10}$ (1 in 1.9 billion)
Producing Well	Base Case (Tubing Flow)	Number/(Well•year)	$1.32 \cdot 10^{-7}$ (1 in 7.5 million)	$2.01 \cdot 10^{-6}$ (1 in 497 thousand)	$5.21 \cdot 10^{-8}$ (1 in 19 million)
Non-Producing Well	Base Case (Tubing Flow)	Number/(Well•year)	$2.20 \cdot 10^{-8}$ (1 in 45 million)	$2.23 \cdot 10^{-7}$ (1 in 4.5 million)	$9.70 \cdot 10^{-9}$ (1 in 102 million)
Pipeline Ruptures	End Pipe Rupture	Number/(km•year)	$3.63 \cdot 10^{-7}$ (1 in 2.8 million)	$1.52 \cdot 10^{-6}$ (1 in 0.6 million)	$8.00 \cdot 10^{-9}$ (1 in 125 million)
	ESD Valve Rupture	Number/(km•year)	$2.00 \cdot 10^{-9}$ (1 in 500 million)	$1.70 \cdot 10^{-8}$ (1 in 59 million)	$3.37 \cdot 10^{-11}$ (1 in 29 billion)
	Centre Pipe Rupture	Number/(km•year)	$4.13 \cdot 10^{-6}$ (1 in 242 thousand)	$4.52 \cdot 10^{-6}$ (1 in 221 thousand)	$1.03 \cdot 10^{-7}$ (1 in 9.7 million)
	Decay to Steady State	Number/(km•year)	$5.30 \cdot 10^{-8}$ (1 in 18.8 million)	$1.08 \cdot 10^{-7}$ (1 in 9.3 million)	$6.0 \cdot 10^{-9}$ (1 in 166 million)
Pipeline Leaks	Centre Leak	Number/(km•year)	$1.48 \cdot 10^{-4}$ (1 in 6.7 thousand)	$2.69 \cdot 10^{-4}$ (1 in 3.7 thousand)	$6.88 \cdot 10^{-5}$ (1 in 14.5 thousand)

Note: All values refer to an uncontrolled sour gas release for a given probability of non-ignition (P_I), emission rate (P_E), source geometry (P_G) and meteorological condition (P_M).

4 RISK CALCULATION EXAMPLES

This section will present several examples of risk calculations for uncontrolled sour gas releases from well blowouts and pipeline leaks and ruptures. The purpose is to show how the approach described in Section 2 can be applied, and to provide some comparison of the relative risk of different aspects of the sour gas industry. The following examples are done:

- blowout of well through tubing while producing,
- blowout of well through casing during servicing,
- blowout of well through casing during drilling,
- rupture of buried pipeline,
- leak from buried pipeline,
- rupture of surface pipeline equipment, and
- leak from surface pipeline equipment.

In addition, from the pipeline examples the reduction of risk by installing ESD valves to reduce the released volume is investigated. First, the source conditions and modelling assumptions will be given. Then, well blowout and pipeline leak and rupture examples will be discussed. Each type of uncontrolled sour gas release (USGR) will be presented in terms of the frequency, consequences and risk.

4.1 Source Conditions and Assumptions

4.1.1 Well Blowouts

The production capability of gas wells in Alberta is usually expressed in terms of an Absolute Open Flow (AOF) potential. The AOF is an estimated theoretical flow which assumes the pressure at the bottom of the well (sandface) is zero. AOF flow rates vary with the flow characteristics of the geological formation and are typically larger for deeper formations. In Alberta, the larger rates are most likely to occur in the foothills regions.

The surface deliverability of a well will be less than the AOF value due to frictional effects. Table 4.1 compares the surface deliverability (*as a percentage of the AOF*) for a selected typical well and the flow cases. The table shows that the tubing has the greatest effect in reducing the surface deliverability for wells which have the highest production capabilities. For wells with a low production capability, the effect of tubing in reducing surface deliverability is minimal.

Table 4.1

Surface Deliverability as a Function of Well AOF.

Sandface AOF (10^3 m^3/d)*	Casing Flow	Annulus and Tubing Flow	Annulus Flow	Tubing Flow
5000	57.4%	52.2%	39.3%	8.5%
1000	95.0	82.5	76.0	26.0
500	98.0	96.0	92.0	46.0
100	99.0	98.0	97.0	90.0
50	99.2	99.2	99.2	98.6

* At 15°C and 101.3 kPa.

The values in Table 4.1 were based on the following well conditions:

- Well depth (m) 2660
- Casing inside diameter (mm) 156.3
- Tubing outside diameter (mm) 73.0
- Tubing inside diameter (mm) 62.0
- Reservoir pressure (kPa) 15,900
- Reservoir temperature (°C) 75

Table 4.2 summarizes the source parameters for well releases. For the purposes of evaluation, a sandface AOF of $1000 \cdot 10^3$ m^3/d was selected. The tubing flow case assumes that the maximum release rate is limited by flow through the tubing ($260 \cdot 10^3$ m^3/d). A further restriction assumes the failure will result in a horizontally oriented jet released in the direction of the wind (referred to as a Downwind Jet). The presence of a wing valve at the well head was assumed to divert the vertical flow in the tubing to a horizontal release. Wing valves are smaller than the master valves on the wellhead. A wing valve diameter of 52.4 mm was assumed to further restrict the release rate ($240 \cdot 10^3$ m^3/d).

The casing flow cases assume that the maximum release rate is limited by flow through the casing ($950 \cdot 10^3$ m^3/d). The jet is assumed to be deflected horizontally in the direction of the wind. Casing flow can occur during drilling or servicing operations.

Table 4.2

Well Blowout Source Assumptions.

	Tubing Flow During Production	Casing Flow During Drilling and Servicing
Sandface AOF (10^3 m^3/d)*	1000	1000
Release Rate (10^3 m^3/d)*	240	950
Release Diameter (mm)	52.4	156.3
Gas Temperature (°C)	40	40
Release Height (m)	1	1
Release Angle (°)	0	0
Drag Coefficient (CD)	0	0

* At 15°C and 101.3 kPa.

4.1.2 Pipeline Leaks and Ruptures

Table 4.3 indicates the range and typical values of sour gas pipeline parameters in Alberta. For sour gas pipelines located near urban centres, emergency shut down valves (ESD) are located every 2000 to 3000 m to reduce the amount of gas which could be vented to the atmosphere in the event of a rupture. In remote rural settings, a sour gas pipeline may not have any intermediate ESD valves.

Table 4.4 summarizes the emission scenarios selected for a pipeline rupture. The mass of the gas released to the atmosphere was assumed to be 30 percent larger than the mass of gas contained in the ruptured pipeline segment which is isolated from the rest of the system by ESD valves. This 30 percent factor accounts for the additional gas released to the atmosphere during the time required for the ESD valves to respond to the rupture.

Table 4.3

Sour Gas Pipeline Parameters.

Parameter	Range	Typical
Length (m)	500 to 25,000	2000 to 10,000
Diameter (mm)	60.3 to 610.0	88.9 to 168.3
Maximum Operating Pressure (kPa)	700 to 39,700	3000 to 10,000
Gas Temperature (°C)	5 to 45	5 to 45

Table 4.4

Pipeline Leaks and Rupture Source Assumptions.

	Buried Pipeline	Surface Pipeline
Length (m)	6000 and 3000	3000
Diameter (mm)	254.5	254.5
Pressure (kPa)	5000	5000
Temperature (°C)	30	30
Friction Factor	.014	.014
Hole Size (%)		
Rupture	100	100
Leak	1	1
Release Height (m)	0	1
Release Angle (°)		
Rupture	10	0
Leak	0	0
Drag Coefficient (CD)		
Rupture	2.0	0.0
Leak	3.0	0.0
Excess Mass (δ)	0.3	0.3

4.1.3 Gas Properties

The composition and associated properties of the sour gas are required to model an uncontrolled sour gas release. It is recognized that sour gas compositions in Alberta represent a wide spectrum of H_2S contents, molecular masses, specific heats and heating values. For the purposes of model evaluation, the gas composition and properties given in Table 4.5 were used.

Table 4.5

Gas Composition Assumptions.

Composition (Volume Fraction)	
C_1	0.550
C_2	0.005
C_3	0.001
C_4	0.001
H_2S	0.300
CO_2	0.123
N_2	0.020
Total	1.000
Molecular Mass (kg/kmole)	25.27
Specific Heat C_P (J/(kg K))	1402
Heat of Combustion (MJ/m^3)*	25.74
Compressibility at Pipeline Conditions	0.83

* Low heat value (15°C and 101.3 kPa).

4.1.4 Meteorology

Table 4.6 summarizes the meteorology scenario used. The mixing height Z_i, Monin-Obukhov length L and friction velocity U^* values given in the table depend on wind speed and are calculated from the meteorological preprocessor formulations contained in GASCON2.

For the base case well and pipeline release scenarios, minimal plume rises are expected for the unignited case. Experience shows that the maximum potential hazard zones associated with this type of release tend to occur under low wind speed, stable conditions. The meteorological base case presented in Table 4.6 represents "worst-case" conditions. That is, the largest distances to critical concentration values are associated with the stable conditions given in the table. For all other meteorological conditions, the predicted distances are expected to be smaller. The meteorological case presented in Table 4.6 has a probability of occurrence (P_M) of 6.3% (based on Calgary International Airport data, 1980 to 1984). Further, the probability that the wind is from the west during the low wind speed, stable conditions (P_θ) is 14.9%.

Table 4.6

Meteorological Assumptions.

Stable Conditions	
Surface Roughness Z_O (m)	0.1
Anemometer Height Z_{REF} (m)	10.0
Temperature T_A (°C)	0.0
Pressure P_A (kPa)	89.0
Temperature Gradient dT/dZ (K/m)	0.03
Surface Heat Flux H_O (W/m^2)	-15.0

4.1.5 Detrimental Effects

Human Vulnerability

The triple shifted Rijnmond parameters are used for the reasons given in Volume 5 (Alp *et al*, 1990).

Exposure Times

The longer the exposure time to a given average H_2S concentration, the greater the probability of lethality. For this evaluation, an exposure time of one hour was assumed for steady-state well releases. It is expected that wells would be ignited within an hour. Shorter exposure times could result from the early ignition of the escaping sour gas release. For transient pipeline releases, the exposure time at given point was assumed to be determined by the duration of the sour gas cloud as it moves past the given point. Shorter exposure times could result from the receptor leaving the area or earlier ignition of the uncontrolled sour gas release.

Population Density

A uniform population density of 1 person per hectare was assumed. As can be seen from Table 4.7, the selected density is twice that of rural residential (low) land use.

Table 4.7

Typical Population Densities for Alberta.

Land Use	Population Density (People/ha)
Urban Residential (High) Urban Residential (Low)	90 15
Rural Residential (High) Rural Residential (Low)	5 0.5
Agricultural (High) Agricultural (Low)	0.1 0.001
Provincial Average City of Calgary	0.004 12

Set Back Distances

A set back distance of 500 m was assumed for the well and pipeline examples.

Shelter

Being indoors affords considerable protection for short-term exposures. The probability of receiving a lethal toxic load generated by GASCON2 assumes that exposed people are outdoors, directly exposed to the plume. For these examples, the probability that the receptor is outdoors (P_R)is assumed to be 100%.

4.2 Well Blowouts

4.2.1 Frequency

Table 4.8 summarizes the frequencies and probabilities used in the examples. The values of F_H, P_I, P_M and P_θ were obtained from Section 3. The probability of emission rate (P_E) and release geometry (P_G) were set to the producing, tubing flow downwind jet values. This allows a comparison of calculated risk values to be made with all event probabilities equal except the historical blowout frequency and probability of non-ignition.

Table 4.8

Well Blowout Event Frequency Summary

		Drilling Casing Flow Downwind Jet	Producing Tubing Flow Downwind Jet	Servicing Casing Flow Downwind Jet
USGR	F	$5.6 \cdot 10^{-3}$	$4.2 \cdot 10^{-9}$	$1.6 \cdot 10^{-8}$
Well Blowout	F_H	$4.5 \cdot 10^{-4}$	$3.6 \cdot 10^{-6}$	$1.4 \cdot 10^{-5}$
Non-Ignition	P_I	0.011	1.0	0.051
Emission Rate	P_E	0.050	0.50	0.50
Release Geometry	P_G	0.25	0.25	0.25
Meteorology	P_M	0.063	0.063	0.063
Wind Direction	P_θ	0.15	0.15	0.15
Receptor Outdoors	P_R	1.0	1.0	1.0

USGR - Uncontrolled Sour Gas Release

F - Frequency (events/year)

F_H - Frequency (blowouts/year)

P - Probability (fraction)

4.2.2 Consequences

Figure 4.1 shows the predicted ground level, centreline H_2S concentrations. Figure 4.2 shows the probability of receiving a lethal toxic load ($P_{L_{ijkl}}(x,y)$) along the centreline of the plume for each of the example well blowouts. The higher flows associated with casing flow result in larger exposure zones.

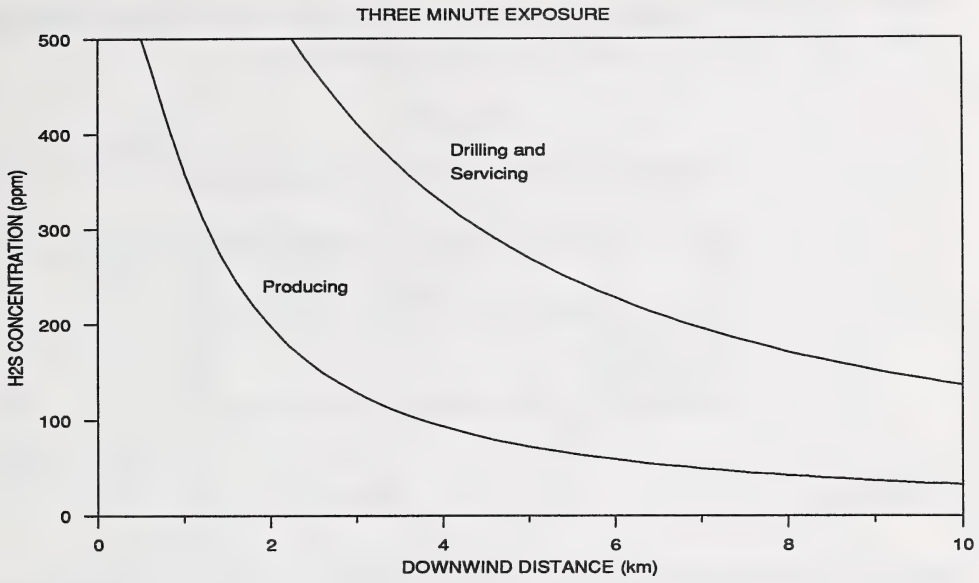


Figure 4.1

Predicted H_2S Concentrations for Selected Well Blowout Examples.

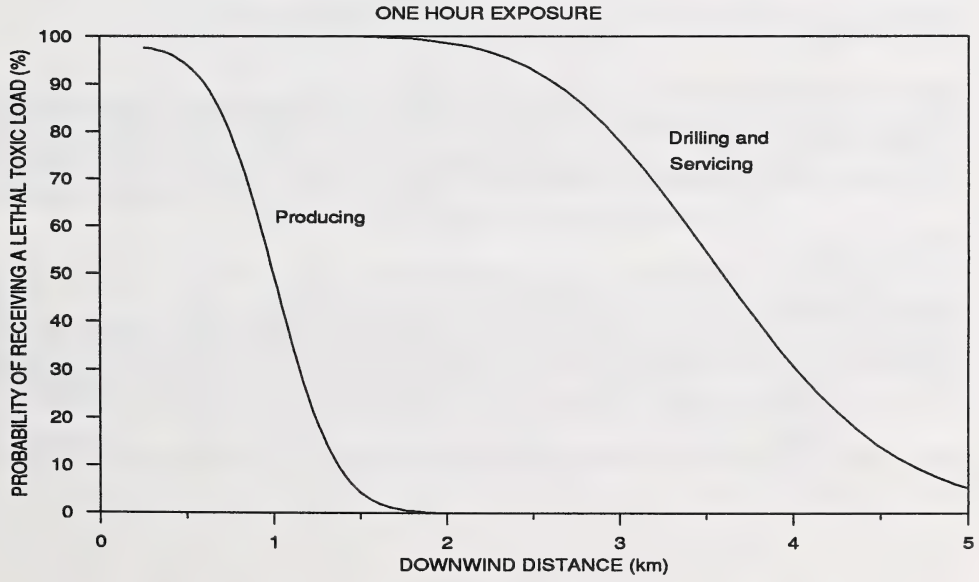


Figure 4.2

Predicted Lethality for Selected Well Blowout Examples.

Table 4.9 gives the potential fatalities ($N_{F_{ijkl}}$). Higher potential fatalities are predicted for the larger release rates during drilling and servicing operations.

Table 4.9

Potential Fatalities for Well Blowout Events

	Potential Fatalities (fatalities/event)
Drilling	37
Producing	5
Servicing	37

4.2.3 Risk

Risk is the frequency times the consequences. Estimates of individual and societal risk are provided. These are **not** the facility risk; they are only the incident risk due to a horizontal, downwind jet for the flow rate considered. This event is considered to be the worst case. Facility risk is obtained by summing over **all** combinations of emission rate, release geometry, meteorology and wind directions which bring a release to a receptor and the receptor's state (indoor or outdoor).

Individual Risk

Figure 4.3 is a plot of how the individual risk changes with distance east of the well. It must be kept in mind that these plots do not represent facility individual risk. Risk levels would increase when the other combinations of events are included. However, it is apparent that servicing and drilling operations present more risk to the public than production operations.

Societal Risk

Table 4.10 provides the societal risk in terms of potential fatalities per year for the well blowout events. Societal risk for production operations is about one tenth of the other operations for the event modelled. This is because lethal concentrations do not extend as far downwind so the number of people exposed to the release event is less.

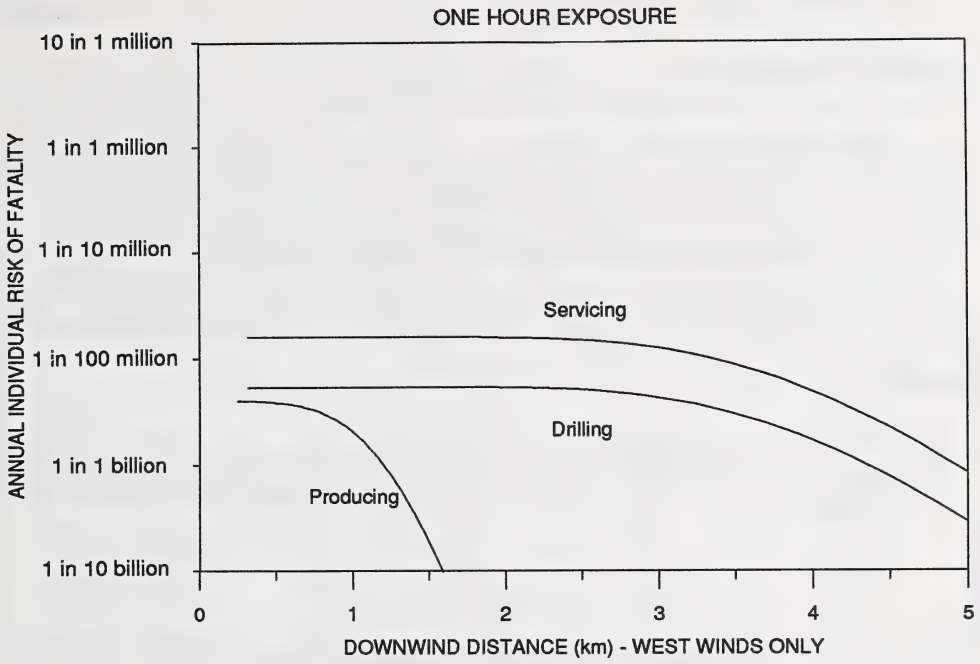


Figure 4.3

Individual Risk for Selected Well Blowout Examples.

Table 4.10

Societal Risk for Well Blowout Events

	Frequency (events/year)	Consequences (fatalities/event)	Societal Risk (fatalities/year)
Drilling	$5.6 \cdot 10^{-9}$	37	$2.1 \cdot 10^{-7}$
Producing	$4.2 \cdot 10^{-9}$	5	$2.1 \cdot 10^{-8}$
Servicing	$1.6 \cdot 10^{-8}$	37	$5.9 \cdot 10^{-7}$

4.3 Pipeline Leaks and Ruptures

4.3.1 Frequency

The frequency of releases from pipelines is given as number/km-year. The risk to a receptor depends on the length of pipeline that could potentially expose him or her to a hazard. Small releases such as leaks, with downwind exposure zones of several hundred metres, can reach a receptor from only a relatively short segment of pipeline. Large releases from ruptures have exposure zones of several thousand metres; therefore, the length of pipeline in which a release could occur and still reach a receptor is larger. For the purpose of this investigation, the blowdown length is used to adjust the frequency from number/km-year to number/year.

Leaks

Table 4.11 gives the frequency of leaks for buried and surface pipe. The probability assumptions are identical, but the frequency of leaks is greater for buried pipe than for surface pipe.

Table 4.11

Pipeline Leak Events Frequency Summary.

		Buried Pipe Leak	Surface Equipment Leak
USGR	F	$8.3 \cdot 10^{-4}$	$1.1 \cdot 10^{-5}$
Pipeline Leak	F_H	$5.0 \cdot 10^{-3}$	$2.8 \cdot 10^{-4}$
Length (km)	L	6	N/A
Non-ignition	P_I	1.0	1.0
Emission Rate	P_E	0.87	0.87
Release Geometry	P_G	0.89	0.89
Meteorology	P_M	0.063	0.063
Wind Direction	P_θ	0.15	0.15
Receptor Outdoors	P_R	1.0	1.0

USGR - Uncontrolled Sour Gas Release Event

F - Frequency (events/year)

F_H - Frequency (number/km-year) for Buried Pipe

F_H - Frequency (events/SE-year) for Surface Equipment

P - Probability (fraction)

N/A - Not Applicable

Ruptures

Table 4.12 summarizes the frequency of ruptures for buried and surface pipe. Surface pipe has a lower chance of rupturing than the buried pipe. It is interesting to note that leaks occur more frequently than ruptures.

Table 4.12

Pipeline Rupture Events Frequency Summary.

		Buried Pipe Centre Rupture	Buried Pipe End Rupture	Surface Equipment End Rupture
USGR	F	$1.3 \cdot 10^{-5}$	$1.3 \cdot 10^{-5}$	$2.9 \cdot 10^{-7}$
Pipeline Rupture	F_H	$6.4 \cdot 10^{-4}$	$6.4 \cdot 10^{-4}$	$7.6 \cdot 10^{-5}$
Length (km)	L	6	2 • 3	N/A
Non-ignition	P_I	1.0	1.0	1.0
Emission Rate	P_E	0.87	0.87	0.87
Release Geometry	P_G	0.11	0.11	0.11
Meteorology	P_M	0.063	0.063	0.063
Wind Direction	P_θ	0.15	0.15	0.15
Receptor Outdoors	P_R	1.0	1.0	1.0

USGR - Uncontrolled Sour Gas Releases Event

F - Frequency (events/year)

F_H - Frequency (events/km-year) for Buried Pipeline

F_H - Frequency (events/SE-year) for Surface Equipment

P - Probability (fraction)

N/A - Not Applicable

4.3.2 Consequences

Figure 4.4 gives the predicted H_2S concentration downwind of a rupture or leak. Ruptures result in much higher H_2S concentrations than leaks. Buried releases experience drag from the interaction with the crater walls.

Figure 4.5 gives the probability of lethality under the centreline ($P_{L_{ijkl}}(x,0)$) for each of the rupture and leak examples. The larger release volumes associated with the 6000 m pipe segment results in larger exposure zones.

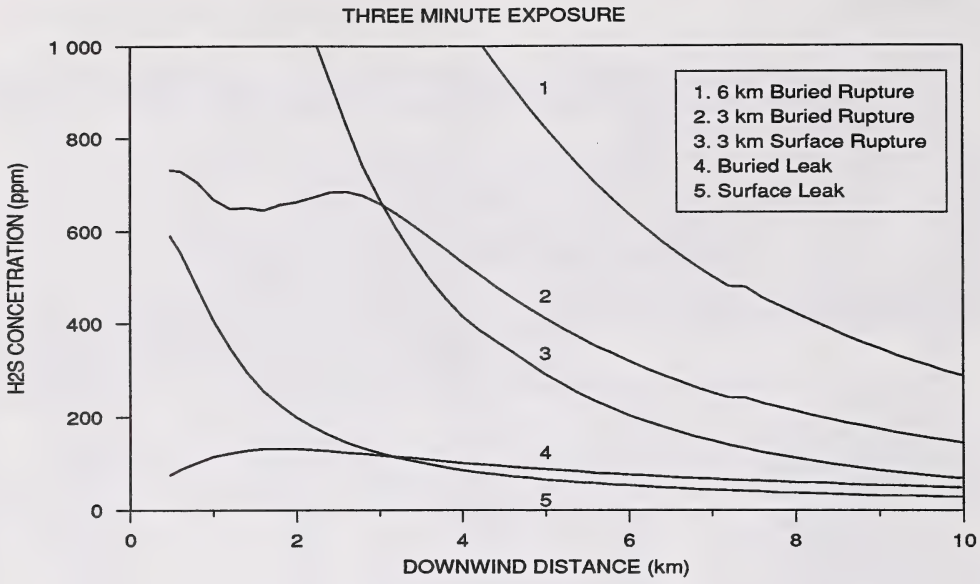


Figure 4.4

Predicted H_2S Concentrations for Selected Pipeline Leak and Rupture Examples.

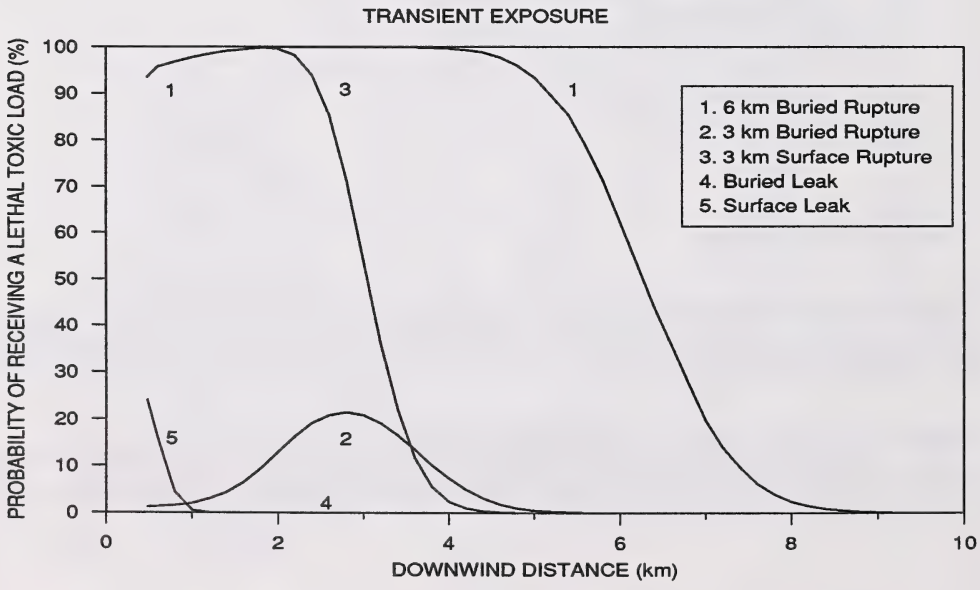


Figure 4.5

Predicted Lethality for Selected Pipeline Leak and Rupture Examples.

Table 4.13 gives the potential fatalities ($N_{F_{ijkl}}$) for each event. The leaks have very low fatalities as the set back distance is about the same as the exposure zone. The highest fatalities are predicted for the centre rupture from a 6000 m buried pipeline.

Table 4.13

Potential Fatalities for Pipeline Leak and Rupture Events.

	Potential Fatalities (fatalities/event)
Surface Pipe Leak	0.03
Buried Pipe Leak	0
Buried Pipe Rupture	
6000 m centre	31
3000 m end	1.4
Surface Pipe Rupture	14

4.3.3 Risk

To determine the system risk, the risk from each release type (leaks and ruptures) and from each component (buried and surface) of the system must be added. For the case without an ESD valve, risk is the sum of the risk due to leaks and ruptures. With an ESD valve, risk is the sum of the risk due to leaks in buried pipe, leaks in surface pipe, ruptures in buried pipe and ruptures in surface pipe.

Individual Risk

Figure 4.6 is a plot of the individual risk east of the centre of the 6000 m pipeline or east of the ESD valve station. The individual risk is greatest for the 6000 m buried pipe alone because the consequences extend further away and the frequency is higher. The risk due to two 3000 m segments is less although the frequency is the same because the consequences are less for all downwind distances. By installing the ESD valve, the overall risk decreases due to the reduction in consequences.

Societal Risk

Table 4.14 provides the societal risk comparison for the pipeline segment without an ESD valve and with one installed. The installation of an ESD valve reduces the societal risk by a factor of 18.

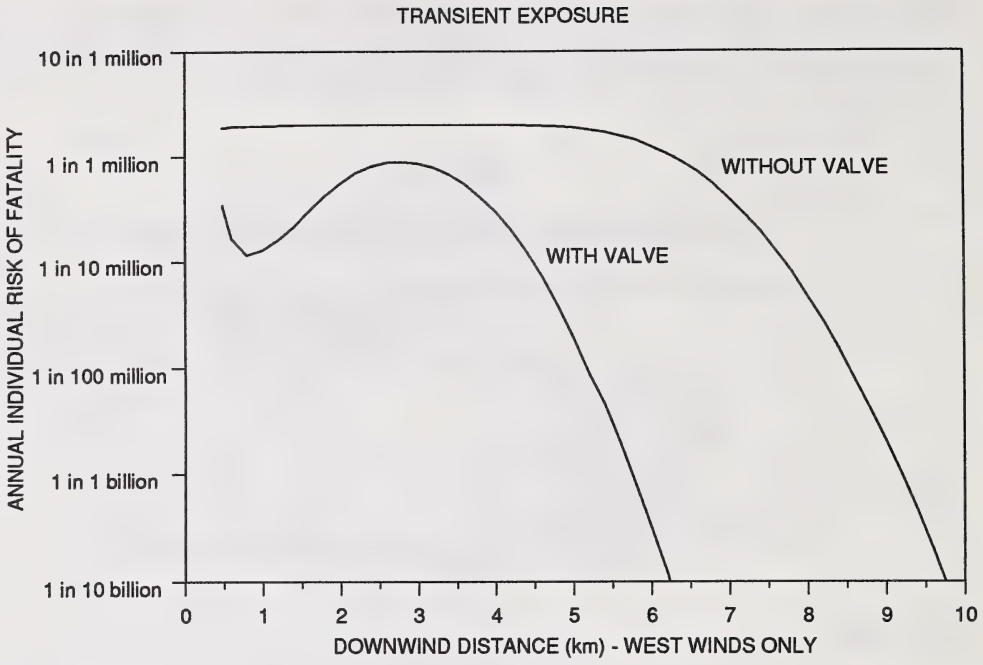


Figure 4.6

Individual Risk for Selected Pipeline Events With and Without an ESD Valve.

Table 4.14

Societal Risk for Pipeline Events With and Without an ESD Valve.

	Frequency (events/year)	Consequences (fatalities/event)	Societal Risk (fatalities/year)
Before No ESD Valve			
Buried Leaks	$8.3 \cdot 10^{-4}$	0.0	0.0
Buried Ruptures	$1.3 \cdot 10^{-5}$	31	$4.1 \cdot 10^{-4}$
Total	N/A	N/A	$4.1 \cdot 10^{-4}$
After With ESD Valve			
Buried Leaks	$8.3 \cdot 10^{-4}$	0.0	0.0
Surface Leaks	$1.1 \cdot 10^{-5}$	0.03	$2.9 \cdot 10^{-7}$
Buried Ruptures	$1.3 \cdot 10^{-5}$	1.4	$1.9 \cdot 10^{-5}$
Surface Ruptures	$2.9 \cdot 10^{-7}$	14	$4.1 \cdot 10^{-6}$
Total	N/A	N/A	$2.3 \cdot 10^{-5}$

5 DISCUSSION, RECOMMENDATIONS AND CONCLUSIONS

A risk assessment approach for estimating the individual risk and societal risk to people due to H_2S exposure from uncontrolled releases of sour natural gas has been developed. The individual risk, calculated for a given release event, consists of estimates of the likelihood of a lethal toxic load occurring at locations downwind of the release point. The societal risk, again for a given event, consists of an estimate of the frequency of human fatalities due to the event.

The approach can be used in support of land developers, municipal planners, regulatory agencies and industry to estimate exposure zones, individual risk and societal risk associated with sour gas facilities. This will aid in regional development and emergency response planning purposes.

The approach presented in this report utilizes the consequence predictions of the GASCON2 model described in Alp *et al.* (1990). During the development of GASCON2, an attempt was made to use state-of-the-art submodels where possible. Indeed, the physics of uncontrolled sour gas releases has dictated that this be so.

The approach consists of a frequency analysis method with historical frequency of well blowouts and pipeline ruptures in Alberta. The probability of meteorological conditions must be supplied by the user. The following have not been incorporated into the approach:

- Facility risk module to sum over possible release events.
- Linear risk module to sum over possible release locations along pipeline.

The approach incorporates a number of new features to the estimation of risk from uncontrolled sour gas releases:

- A frequency analysis module, incorporating updated historical uncontrolled release frequency data from Alberta.
- A fluctuating load model to account for turbulence-driven concentration fluctuation in the atmosphere. To the authors' knowledge, GASCON2 is the first model to use a distribution function for the toxic load as defined in this report.
- A probit model for estimating the lethal effect of H_2S exposure to humans. The probit model, through the use of the toxic load concept, is able to give lethality estimates accounting for both concentration level and exposure time. The use of probit methods in risk assessment is a relatively recent development.

5.1 Frequency Analysis: Key Results

Application of the frequency analysis methodology using Alberta-based historical sour gas release data indicates the following:

- The expected frequency of occurrence of an uncontrolled well blowout during drilling of a sour well is $4.53 \cdot 10^{-4}$ blowouts/well drilled (1 in 2207).

- The frequency of this event leading to flow though the drill pipe deflected into a horizontal downwind jet, and all this taking place during a period of very low wind and stable atmospheric conditions (based on Calgary International Airport weather data), is estimated to be $2.53 \cdot 10^{-9}$ events/well drilled.

- The expected frequency of occurrence of an uncontrolled well blowout during the producing phase of a sour gas well is $3.94 \cdot 10^{-4}$ events/(well•year).

- The expected frequency of occurrence of rupture of a buried sour gas pipeline is $6.37 \cdot 10^{-4}$ ruptures/(km•year).

- The expected frequency of occurrence of rupture of a pipeline surface equipment component (e.g., valve/fitting, surface pipe, etc) is $7.6 \cdot 10^{-5}$ ruptures/(SE•year).

5.2 Recommendations for Future Work

It is recommended that:

- The historical database be regularly updated and extended to cover more information.

- The approach be coded into a computer model to determine facility risk from point sources such as wells and surface facilities, and linear sources such as pipelines.

5.3 Conclusions

The Phase I results (Alp *et al.* 1990) indicate that SO_2 concentrations at ground level from an ignited release are significantly smaller than unignited H_2S ground level concentrations. Hence, the following conclusion remains:

- Ignite the plume to convert H_2S to SO_2. The increased plume rise due to combustion gives smaller SO_2 concentrations than the unignited H_2S concentrations.

The risk estimates indicate the following:

- Providing reliable ignition devices and procedures for manned operations results in lower risk of H_2S fatality.

- Production operations result in less risk to the public than drilling or servicing operations.

- The installation of additional ESD valves can significantly reduce risk to people in the vicinity of the pipeline, despite the fact that the probability of a rupture increases.

Because it provides quantitative estimates of risk, the approach can be used to evaluate the various risk mitigative measures.

6 REFERENCES

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7 SYMBOL GLOSSARY

Symbol	Description	Section
F_{DT}	fractional down time (fraction)	3.1
F_{H_i}	frequency of hazard i (number/ year)	2.3.1
k	component failure rates	3.1
$N_{F_{ijkl}}$	potential fatalities due to H_2S for outdoor receptors if event defined by hazard i, emission rate j, geometry k and meteorological condition l were to occur (fatalities/ event).	2.3.1
P_{E_j}	probability of emission rate j for hazard i	2.3.1
P_{G_k}	probability of geometry k for hazard i	2.3.1
P_{I_i}	probability of non-ignition for hazard i	2.3.1
$P_{L_{ijkl}}(x,y)$	probability of receptor located outdoors at position (x,y) recieving a lethal toxic load of H_2S from event defined by hazard i, emission rate j, geometry k and meteorological condition l.	2.3.1
P_{M_l}	probability of meteorological condition l	2.3.1
P_R	probability of receptor being outdoors	2.3.1
$P_{\theta_{lm}}(x,y)$	probability of wind direction m, from source (0,0) to receptor (x,y) during meteorological condition l	2.3.1
$R_{I_{ijkl}}(x,y)$	individual risk of fatality due to H_2S for outdoor receptor at position (x,y) for hazard i, emission rate j, geometry k and meteorological condition l (chances of fatality/ year)	2.3.1
$R_{S_{ijkl}}$	societal risk of fatality due to H_2S for outdoor receptors for hazard i, emission rate j, geometry k and meteorological condition l (fatalities/year)	2.3.1
t	time between component inspections	3.1

Subscript

i	hazard i
j	emission rate j
k	geometry scenario k
l	meteorological conditions l
m	wind direction m

APPENDIX A

WELL AND PIPELINE RELEASE STATISTICS AND FAULT TREE SYMBOLS

TABLE A.1

DRILLING WELL BLOWOUT, BLOW AND KICK STATISTICS

YEAR	BLOWOUTS FOR ALL WELLS			BLOWS	KICKS	ALL WELLS DRILLED
	SWEET	SOUR	TOTAL			TOTAL
1975	3	0	3	6	48	4352
1976	0	0	0	1	71	5320
1977	4	2	6	4	148	5498
1978	0	0	0	4	197	5958
1979	2	0	2	9	234	6032
1980	2	0	2	9	281	7731
1981	0	1	1	11	274	6990
1982	2	1	3	6	148	5661
1983	0	1	1	3	188	4779
1984	4	0	4	0	249	6301
1985	1	0	1	2	343	8601
1986	2	0	2	2	223	4571
1987	1	0	1	1	237	5274
1988	2	0	2	4	277	6718
TOTAL	23	5	28	62	2918	83786

SOURCE: Blowouts Table 4.1, ERCB Volume 7
Blows Table 4.2, ERCB Volume 7
Kicks Table 4.8, ERCB Volume 7
All Wells Drilled Table 3.2, Page A-20 ,ERCB Volume 7

NOTES: Wells drilled include successful and unsuccessful conventional wells and do not include oil sands, crude bitumen, water and observation wells.

TABLE A.2

DRILLING OPERATION IN PROGRESS AT TIME OF KICK

YEAR	DRILL	CIRC	CORE	LOG	TRIP IN	TRIP OUT	RUN CSG	TEST	OTHER	TOTAL
1975	23	6	2	0	1	14	0	2	0	48
1976	42	10	0	0	0	15	1	2	1	71
1977	60	19	9	1	8	30	3	18	0	148
1978	85	29	4	4	11	42	1	21	0	197
1979	128	6	3	3	20	56	5	13	0	234
1980	107	3	9	2	32	120	4	3	1	281
1981	109	5	4	0	27	112	4	8	5	274
1982	54	0	8	0	17	67	0	2	0	148
1983	84	3	8	0	23	62	4	3	1	188
1984	109	2	7	2	34	86	5	4	0	249
1985	132	8	14	1	50	122	12	4	0	343
1986	97	5	5	1	17	93	4	1	0	223
1987	87	4	3	0	33	100	8	2	0	237
1988	122	10	6	4	38	81	7	6	3	277
TOTAL	1239	110	82	18	311	1000	58	89	11	2918

SOURCE: Table 4.8, ERCB Volume 7

NOTE: Other kick causes were equally distributed amongst those identified.

TABLE A.3

PRODUCING GAS WELL STATISTICS

YEAR	BLOWOUT OCCURRENCES			NUMBER OF GAS WELLS				
	SWEET GAS WELLS	SOUR GAS WELLS	TOTAL	SWEET (SEAB)*	TOTAL SWEET	SOUR	TOTAL -SEAB	TOTAL
1976	3	0	3	5419	8763	912	4256	9675
1977	1	1	2	7380	11601	1016	5237	12617
1978	3	1	4	8835	13704	1101	5970	14805
1979	3	0	3	10046	15494	1142	6590	16636
1980	3	0	3	11807	17853	1178	7224	19031
1981	2	1	3	13451	20256	1267	8072	21523
1982	2	1	3	15154	22684	1322	8852	24006
1983	3	0	3	15778	23954	1411	9587	25365
1984	2	1	3	16586	25205	1512	10131	26717
1985	3	0	3	17889	27027	1640	10778	28667
1986	1	0	1	18629	28289	1697	11357	29986
1987	2	2	4	18406	28267	1762	11623	30029
1988	3	0	3	18862	29228	1828	12194	31056
TOTAL	31	7	38	178242	272325	17788	111871	290113

Source: Blowouts — Table 4.19, ERCB Volume 7
Number of Wells — Table 3.10, Page A-28, ERCB Volume 7

* South East Alberta

TABLE A.4

NON-DRILLING GAS WELL FAILURE CAUSES

YEAR	EQUIPMENT FAILURE			INCORRECT PROCEDURE			ENVIRONMENTAL ACCIDENT			THIRD PARTY			SUB-TOTALS			TOTAL
	PROD. SOUR	NON-PROD. SOUR	SWEET	PROD. SOUR	NON-PROD. SOUR	SWEET	PROD. SOUR	NON-PROD. SOUR	SWEET	PROD. SOUR	NON-PROD. SOUR	SWEET	PROD. SOUR	NON-PROD. SOUR	SWEET	
1976	0	1	3	0	0	2	0	0	0	0	0	1	0	1	6	7
1977	1	0	1	0	0	0	0	0	0	0	0	3	1	0	4	5
1978	0	0	5	1	0	1	0	0	0	0	0	1	1	0	7	8
1979	0	1	2	0	1	2	0	0	0	0	0	0	0	1	4	5
1980	0	0	2	0	0	1	0	0	0	0	0	1	0	1	4	5
1981	0	0	2	1	0	1	0	0	0	0	0	1	1	0	4	5
1982	0	0	1	1	0	0	0	0	1	0	0	4	1	0	4	7
1983	0	0	2	0	0	2	0	0	0	0	0	2	0	0	6	6
1984	0	0	1	1	0	1	0	0	0	0	1	0	1	1	2	4
1985	0	2	2	0	0	0	0	0	1	0	0	3	0	2	6	8
1986	0	1	2	0	0	1	0	0	0	0	0	2	0	1	5	6
1987	2	0	1	0	0	1	0	0	0	0	0	3	2	0	5	7
1988	0	0	6	0	0	1	0	0	0	0	0	2	0	0	9	9
TOTAL	3	5	30	4	1	13	0	0	2	0	1	23	7	7	68	82

SOURCE: Tables 4.15, 4.16 and 4.17, ERCB Volume 7
ERCB ST 86-4, Oil and Gas Well Blowout Report

NOTE: Equipment Failure encompasses failure by any mechanism, including corrosion.
Environmental accident includes failure due to lightning strikes and damage by lake ice.
Sour wells are those wells containing any amount of H_2S.

TABLE A.5

CONCORD STUDY SOUR GAS PIPELINE RUPTURE STATISTICS (1975-1989)

Failure	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	ERCB TOTAL	EDITED TOTAL	REASON
Rupture of Buried Pipe																		
Corrosion																		
Internal	1			1			3		1			2			1	9	6	a
External				1	1		1				1					4	3	b
At girth or Fillet Weld																0	0	
Inadequate Pipe Material																0	0	
External Forces																		
Construction Damage								1								1	1	
Damage by Others			1						2		1	1				5	3	c
Earth Movement																0	0	
Equipment Failures																		
Weld Failure											1	1				2	2	
Pipe Failures					3		1		1	3	1		1	1	2	13	10	d
Operational Failures																		
Overpressure	1					1										2	2	
Operator Error										1						1	1	
Failure of Surface Equipment																		
Corrosion																		
Internal																0		
External																0		
External Forces																		
Construction Damage																0		
Damage by Others																0		
Earth Movement																0		
Equipment Failures																		
Failure of an Installation																0		
Weld Failure																0		
Pipe Failures																		
Wrong Pipe																0		
Excessive Stresses																0		
Valve/Fitting Failure																		
Incorrect Installation																0		
Inadequate Material																0		
Damaged Valve/Fitting				1								1				2	2	
Operational Failures																		
Overpressure																0		
Operator Error																0		
Miscellaneous/Other		1														1	1	
TOTAL	2	1	1	3	0	1	3	1	2	4	4	4	1	1	3	40	31	9

Source: ERCB EIS System Printout (1990) Table 5.6, ERCB Volume 7
EIS - Environmental Information System

Note:
a 1 test failure in 1986 and 2 in 1981 were omitted
b 1 test failure in 1979 was omitted
c 2 construction failures in 1983 were omitted
d 3 spiral weld pipe failures in 1979 were omitted.

TABLE A.6

LENGTH OF SOUR GAS PIPELINE SERVICE IN ALBERTA

YEAR	NUMBER OF SOUR WELLS (Gas and Gas Condensate)	NUMBER OF KM OF SOUR GAS (4) PIPELINE
1975	826	1 500*
1976	912	1 600
1977	1016	1 800
1978	1101	2 100
1979	1142	2 300
1980	1178	2 500
1981	1267	2 700
1982	1322	2 900
1983	1411	3 000*
1984	1512	3 500*
1985	1640	4 000*
1986	1697	4 400*
1987	1762	4 600*
1988	1828	5 100*
1989	1936	5 500*
Total	N/A	47 500

Notes: Wells > 0.01% H_2S.
Gas pipelines can refer to gas or gas condensate line.
* Estimates from ERCB, others based on regression analysis of km/well with respect to time, using ERCB estimates.
Same Table as Table 5.5, ERCB Volume 7

TABLE A.7

SURVEY OF SEVEN SOUR GAS SYSTEMS TO DETERMINE SOME TYPICAL PIPELINE PARAMETERS

LOCATION	TOTAL LENGTH (km)	ESD's on MAIN LINE	ESD's at WELLS	CHECK VALVES
Coleman	94	11	13	4
Edson	153	4	80	75
Stolberg	62	4	(transmission line only)	
Okotoks	52	12	21	25
Jumping Pound	140	12	45	15
Crossfield	127	23	64	50
Bashaw	60	7	(transmission line only)	
Totals	688	73	223	169

Source: Cassely/ Holizki 1987
Same as Table 5.2, ERCB Volume 7

TABLE A.8

CONCORD STUDY SOUR GAS PIPELINE LEAK STATISTICS (1975-1989)

Failure	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	ERCB TOTAL
Corrosion																
Internal	21	7	8	5	14	5	4	5	6	11	14	9	7	7	12	135
External	2	1		4	6		2	9	1	4	5	7	3	10	4	58
At girth or Fillet Weld	1															1
Inadequate Pipe Material																0
External Forces																
Construction Damage	1			1						1						3
Damage by Others										1						1
Earth Movement								1			1					2
Equipment Failures																
Weld Failure		1	2	2	1		1	5	3	3						18
Pipe Failures				2		1	1	3			1		1	1	9	19
Operational Failures																
Overpressure																0
Operator Error																0
Equipment Failures																
Damaged Valve/ Fitting												1	1			2
Incorrect Installation		1														1
Miscellaneous/Other	2		1									1		1		5
TOTAL	27	10	11	14	21	6	8	23	10	20	21	18	12	19	25	245

Source: ERCB EIS System Printout (1990) Table 5.6, ERCB Volume 7
EIS - Environmental Information System

TABLE A.9

FLOW SCENARIO CALCULATIONS FOR PRODUCING WELLS

• Assumptions:	(1)	38 Producing Well Blowouts.
	(2)	26 of the 38 blowouts were during servicing operations.
	(3)	The 12 normal procedure blowouts (38 - 26) were tubing flow.
	(4)	It was assumed that the 26 servicing blowouts were equally distributed among each flow type.

• Thus:

Flow	Number	Probability
Casing Flow	5.5	0.083
Combined Flow	5.5	0.083
Annular Flow	5.5	0.083
Tubing Flow	44 + 5.5	0.751
Total	66	1.000

Geometry For Producing Wells

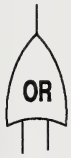
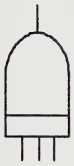
• No data were available regarding geometry of producing well blowouts.
• The following assumptions are made:

	(1)	equal chance of getting a horizontal or vertical jet
	(2)	equal chance of horizontal jet being directed into or with wind
	(3)	no chance of cloud geometry

• Thus:

Release Geometry	Probability
Downwind Jet	0.25
Upwind Jet	0.25
Vertical Jet	0.50
Cloud	0.00
Total	1.000

LOGIC GATE SYMBOLS

GATE SYMBOL	GATE NAME	CAUSAL RELATION
	AND gate	Output event occurs if all input events occur simultaneously
	OR gate	Output event occurs if any one of the input events occurs
	Inhibit gate	Input produces output when conditional event occurs
	Priority AND gate	Output event occurs if all input events occur in the order from left to right
	Exclusive OR gate	Output event occurs if one, but not both, of the input events occur

EVENT SYMBOLS

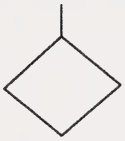
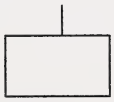
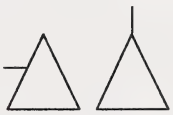
EVENT SYMBOL	MEANING OF SYMBOLS
Circle/Ellipse	Basic event with sufficient data
 Diamond	Undeveloped event
 Rectangle	Event represented by a gate
Oval	Conditional event used with inhibit gate
House	House event. Either occurring or not occurring
 Triangles	Transfer symbol

Figure A.1

Symbols Used in Fault Trees.

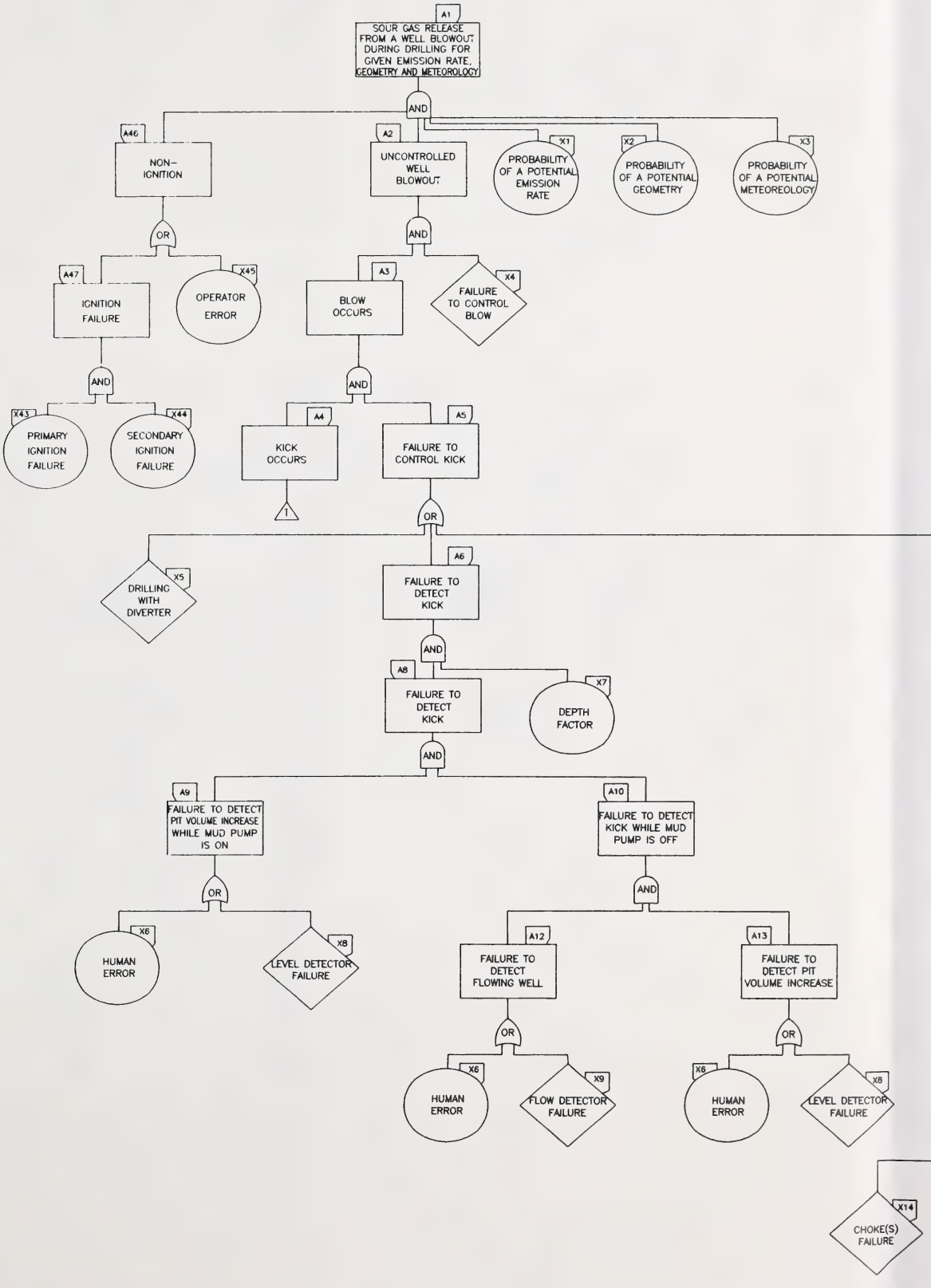
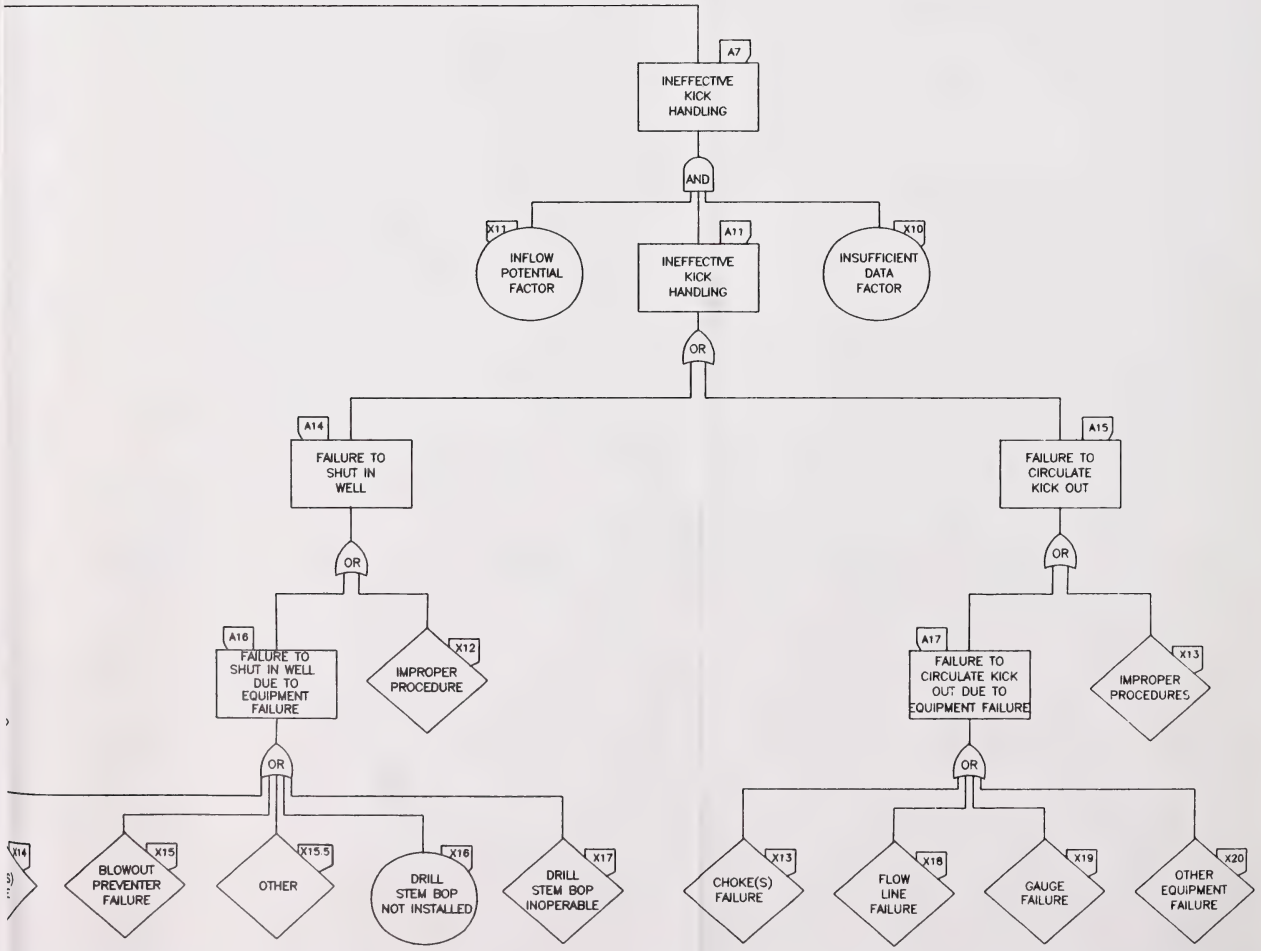

A1
SOUR GAS RELEASE FROM A WELL BLOWOUT DURING DRILLING FOR GIVEN EMISSION RATE, GEOMETRY AND METEOROLOGY
AND
A46
NON-IGNITION
A2
UNCONTROLLED WELL BLOWOUT
X1
PROBABILITY OF A POTENTIAL EMISSION RATE
X2
PROBABILITY OF A POTENTIAL GEOMETRY
X3
PROBABILITY OF A POTENTIAL METEOREOLOGY
OR
AND
A47
IGNITION FAILURE
X45
OPERATOR ERROR
A3
BLOW OCCURS
X4
FAILURE TO CONTROL BLOW
AND
AND
X43
PRIMARY IGNITION FAILURE
X44
SECONDARY IGNITION FAILURE
A4
KICK OCCURS
A5
FAILURE TO CONTROL KICK
1
OR
X5
DRILLING WITH DIVERTER
A6
FAILURE TO DETECT KICK
AND
A8
FAILURE TO DETECT KICK
X7
DEPTH FACTOR
AND
A9
FAILURE TO DETECT PIT VOLUME INCREASE WHILE MUD PUMP IS ON
A10
FAILURE TO DETECT KICK WHILE MUD PUMP IS OFF
OR
AND
X6
HUMAN ERROR
X8
LEVEL DETECTOR FAILURE
A12
FAILURE TO DETECT FLOWING WELL
A13
FAILURE TO DETECT PIT VOLUME INCREASE
OR
OR
X6
HUMAN ERROR
X9
FLOW DETECTOR FAILURE
X6
HUMAN ERROR
X8
LEVEL DETECTOR FAILURE
X14
CHOKE(S) FAILURE

FIGURE A.1a
DRILLING WELL
FAULT TREE



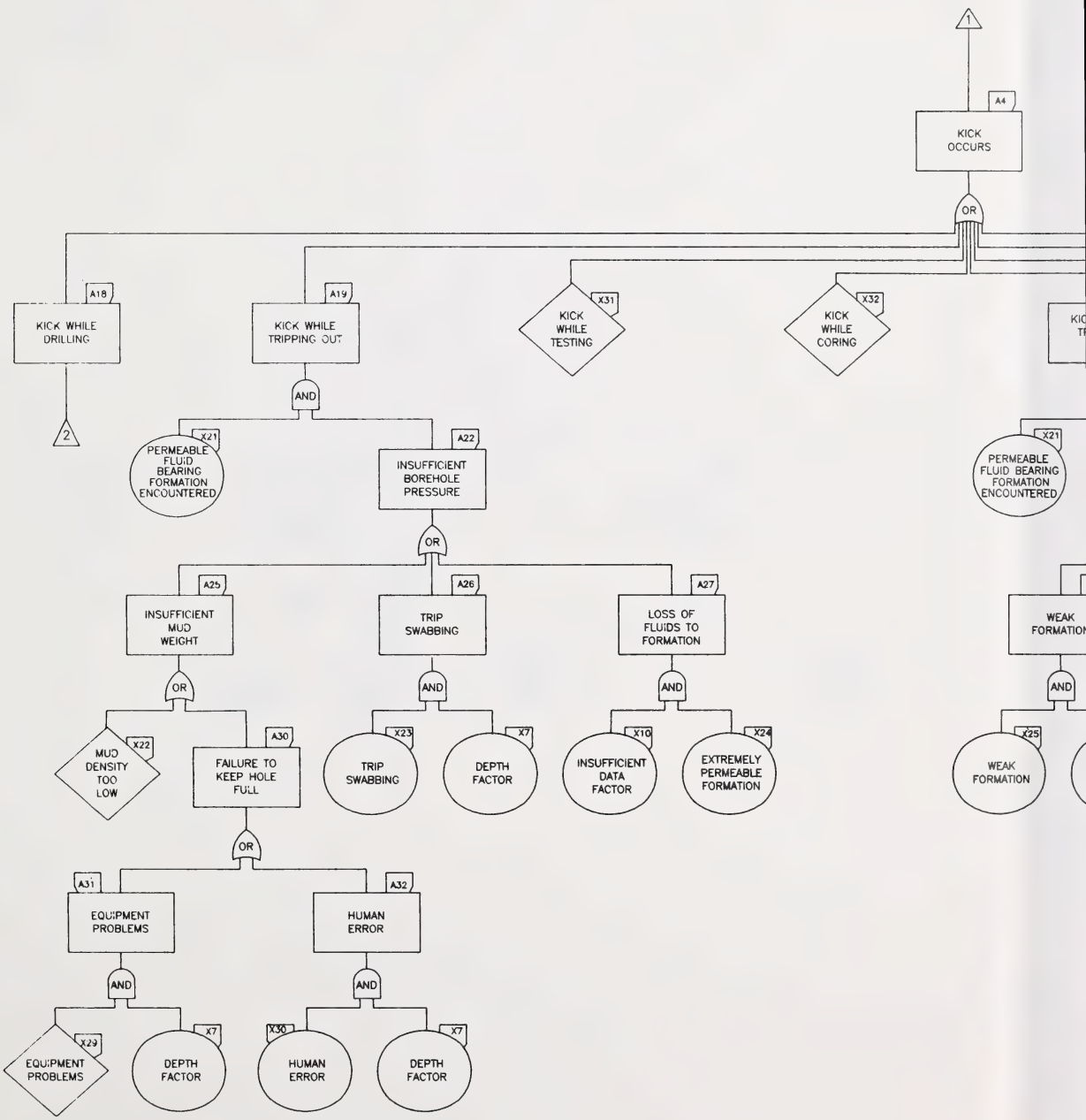
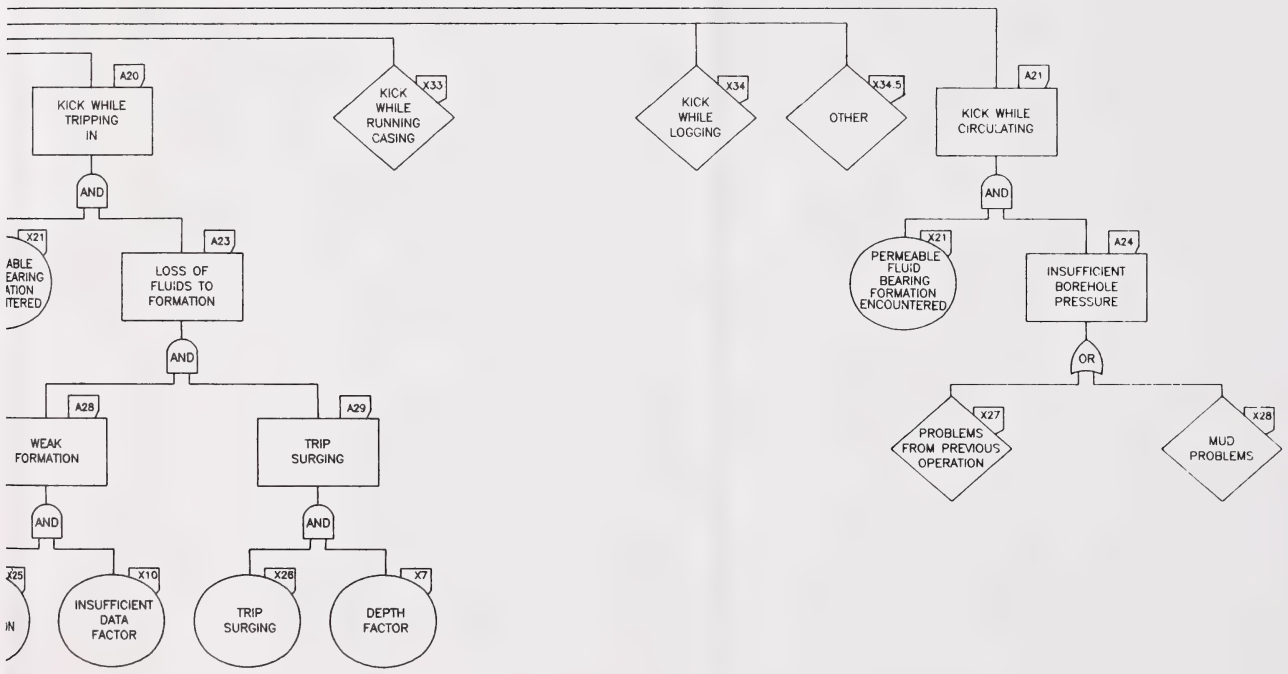

1
A4
KICK OCCURS
OR
A18
KICK WHILE DRILLING
2
A19
KICK WHILE TRIPPING OUT
AND
X21
PERMEABLE FLUID BEARING FORMATION ENCOUNTERED
A22
INSUFFICIENT BOREHOLE PRESSURE
OR
A25
INSUFFICIENT MUD WEIGHT
OR
X22
MUD DENSITY TOO LOW
A30
FAILURE TO KEEP HOLE FULL
OR
A31
EQUIPMENT PROBLEMS
AND
X29
EQUIPMENT PROBLEMS
X7
DEPTH FACTOR
A32
HUMAN ERROR
AND
X30
HUMAN ERROR
X7
DEPTH FACTOR
A26
TRIP SWABBING
AND
X23
TRIP SWABBING
X7
DEPTH FACTOR
A27
LOSS OF FLUIDS TO FORMATION
AND
X10
INSUFFICIENT DATA FACTOR
X24
EXTREMELY PERMEABLE FORMATION
X31
KICK WHILE TESTING
X32
KICK WHILE CORING
X21
PERMEABLE FLUID BEARING FORMATION ENCOUNTERED
WEAK FORMATION
AND
X25
WEAK FORMATION

FIGURE A.1b
DRILLING WELL
FAULT TREE



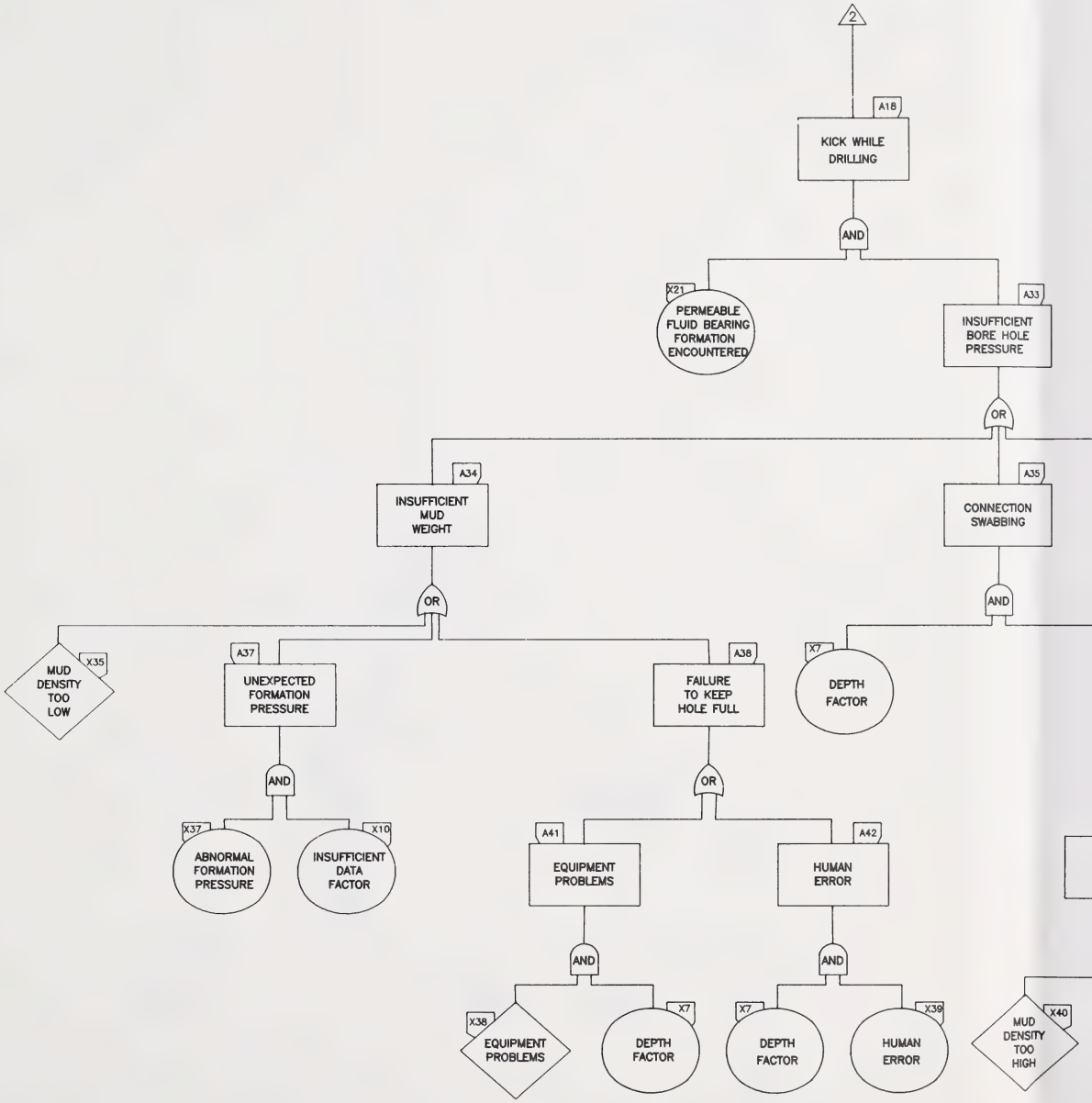
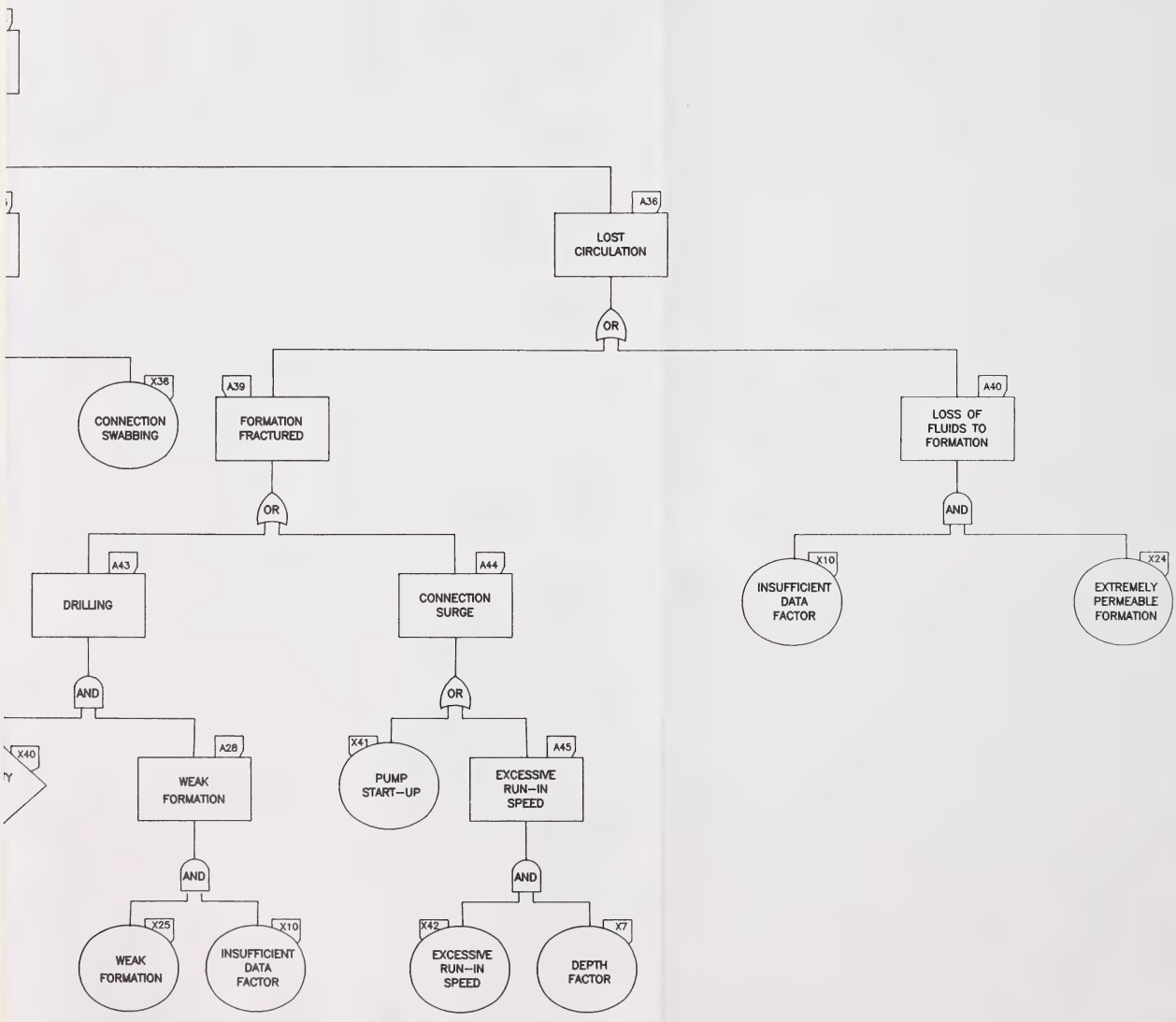

2
A18
KICK WHILE DRILLING
AND
X21
PERMEABLE FLUID BEARING FORMATION ENCOUNTERED
A33
INSUFFICIENT BORE HOLE PRESSURE
OR
A34
INSUFFICIENT MUD WEIGHT
A35
CONNECTION SWABBING
OR
AND
X35
MUD DENSITY TOO LOW
A37
UNEXPECTED FORMATION PRESSURE
A38
FAILURE TO KEEP HOLE FULL
X7
DEPTH FACTOR
AND
OR
X37
ABNORMAL FORMATION PRESSURE
X10
INSUFFICIENT DATA FACTOR
A41
EQUIPMENT PROBLEMS
A42
HUMAN ERROR
AND
AND
X38
EQUIPMENT PROBLEMS
X7
DEPTH FACTOR
X7
DEPTH FACTOR
X39
HUMAN ERROR
X40
MUD DENSITY TOO HIGH

FIGURE A.1c DRILLING WELL FAULT TREE



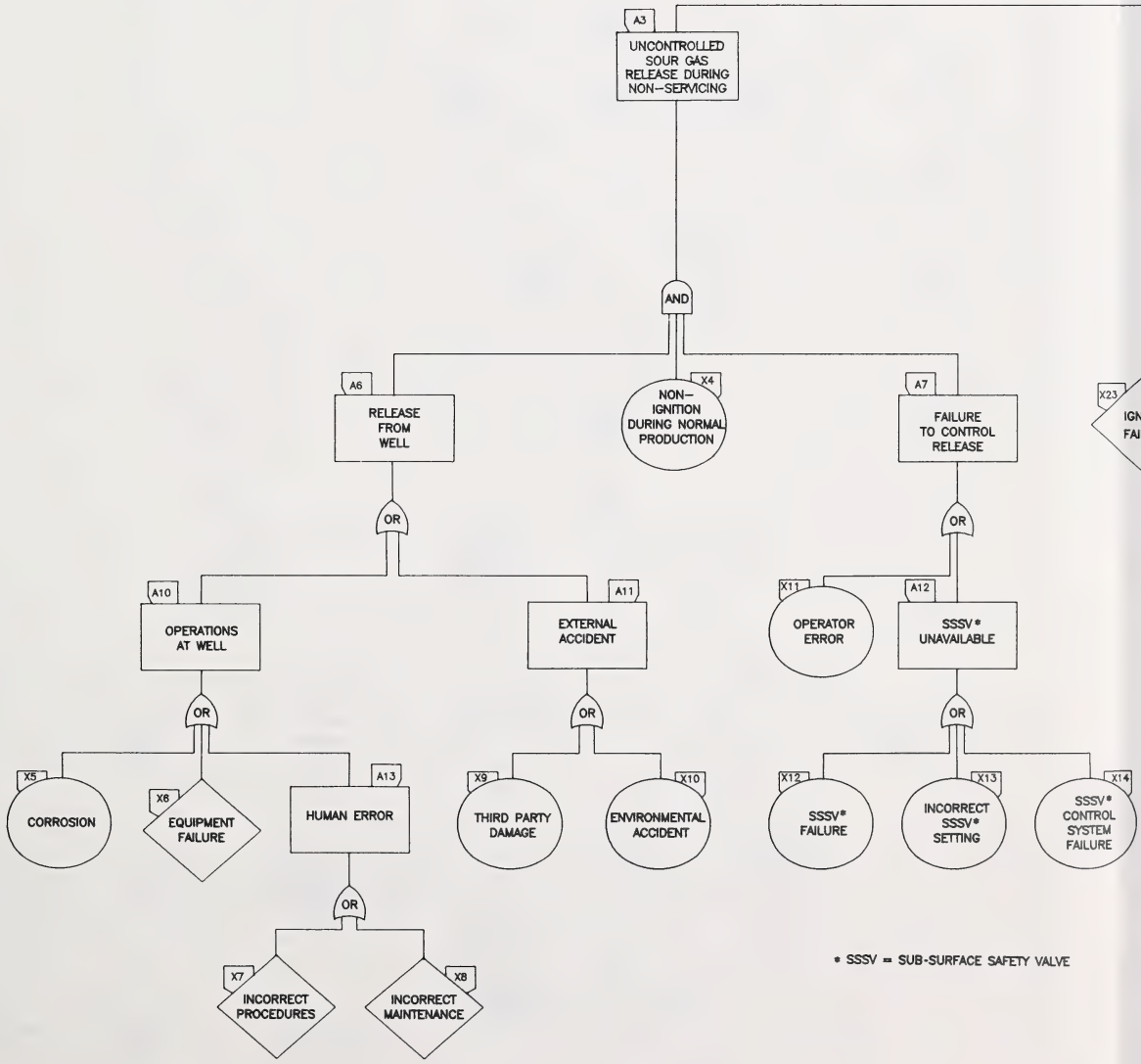
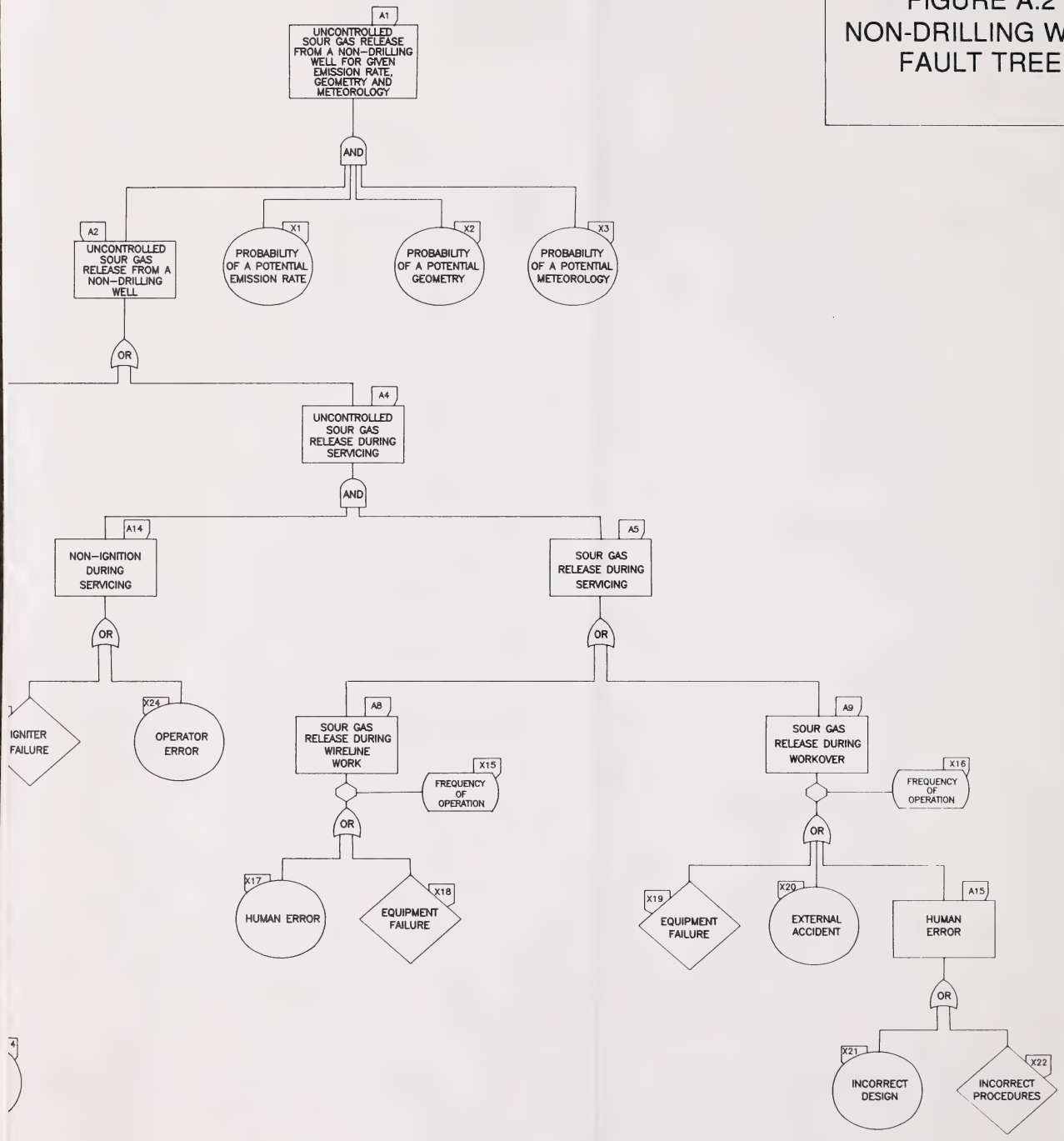

A3
UNCONTROLLED SOUR GAS RELEASE DURING NON-SERVICING
AND
A6
RELEASE FROM WELL
X4
NON-IGNITION DURING NORMAL PRODUCTION
A7
FAILURE TO CONTROL RELEASE
X23
IGNITER FAILURE
OR
OR
OR
A10
OPERATIONS AT WELL
A11
EXTERNAL ACCIDENT
X11
OPERATOR ERROR
A12
SSSV* UNAVAILABLE
OR
OR
OR
X5
CORROSION
X6
EQUIPMENT FAILURE
A13
HUMAN ERROR
X9
THIRD PARTY DAMAGE
X10
ENVIRONMENTAL ACCIDENT
X12
SSSV* FAILURE
X13
INCORRECT SSSV* SETTING
X14
SSSV* CONTROL SYSTEM FAILURE
OR
X7
INCORRECT PROCEDURES
X8
INCORRECT MAINTENANCE
* SSSV = SUB-SURFACE SAFETY VALVE

FIGURE A.2
NON-DRILLING WELL
FAULT TREE



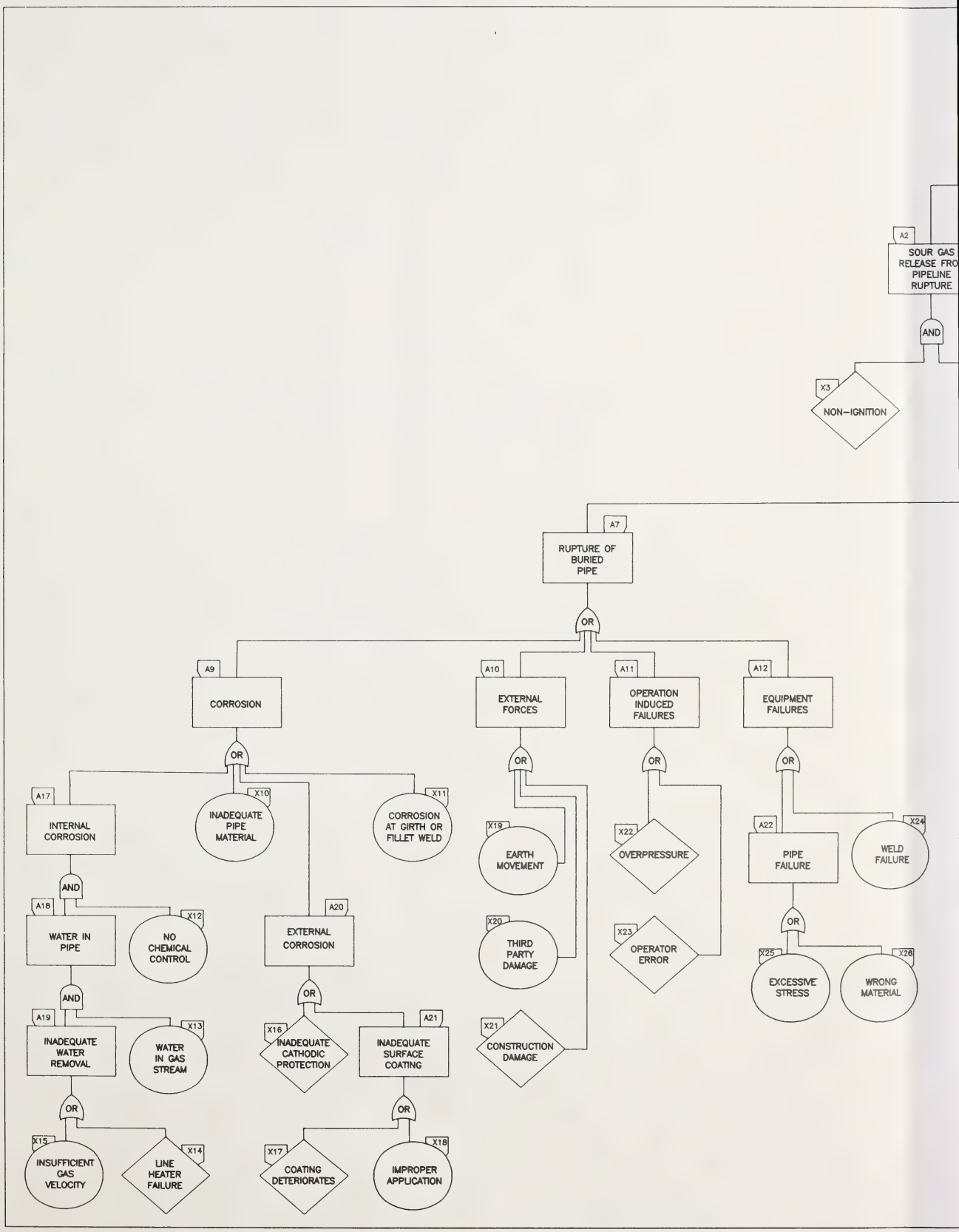
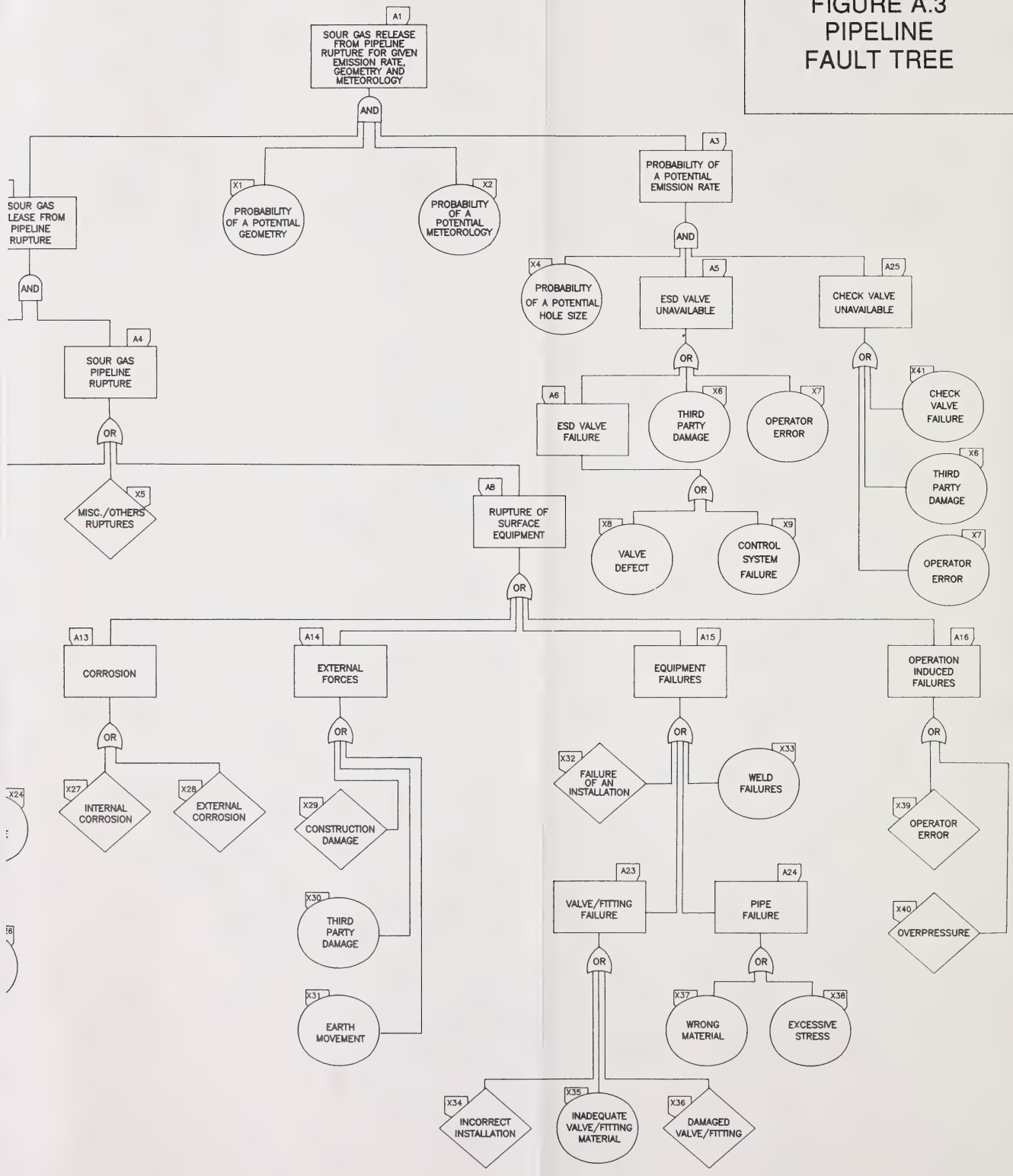

A2
SOUR GAS
RELEASE FRO
PIPELINE
RUPTURE
AND
X3
NON-IGNITION
A7
RUPTURE OF
BURIED
PIPE
OR
A9
CORROSION
A10
EXTERNAL
FORCES
A11
OPERATION
INDUCED
FAILURES
A12
EQUIPMENT
FAILURES
OR
A17
INTERNAL
CORROSION
X10
INADEQUATE
PIPE
MATERIAL
X11
CORROSION
AT GIRTH OR
FILLET WELD
X19
EARTH
MOVEMENT
X22
OVERPRESSURE
A22
PIPE
FAILURE
X24
WELD
FAILURE
AND
A18
WATER IN
PIPE
X12
NO
CHEMICAL
CONTROL
A20
EXTERNAL
CORROSION
X20
THIRD
PARTY
DAMAGE
X23
OPERATOR
ERROR
OR
X25
EXCESSIVE
STRESS
X26
WRONG
MATERIAL
AND
A19
INADEQUATE
WATER
REMOVAL
X13
WATER
IN GAS
STREAM
X16
INADEQUATE
CATHODIC
PROTECTION
A21
INADEQUATE
SURFACE
COATING
X21
CONSTRUCTION
DAMAGE
OR
X15
INSUFFICIENT
GAS
VELOCITY
X14
LINE
HEATER
FAILURE
X17
COATING
DETERIORATES
X18
IMPROPER
APPLICATION

FIGURE A.3
PIPELINE
FAULT TREE



APPENDIX B

DRILLING WELL FAULT TREE QUANTIFICATION PROCEDURE

X1 Probability of a Potential Emission Rate.

- Emission Rate depends on
  - (i) Well deliverability (producing flowrate), P_F.
  - (ii) Probability of flow being up the tubing, annulus, tubing and annulus or open hole, P_O, and
  - (iii) Whether flow is constricted by wellhead equipment, P_C.

  $P(X1) = P_F P_O P_C$
- Well deliverability is a site-specific parameter. For proposed wells two options are possible: (i) estimate risks for certain predefined potential flowrates where $P_F = 1.0$ and is a default probability and (ii) establish a frequency distribution of potential well deliverabilities either through a statistical analysis or Monte Carlo simulation where

$$\int_0^\infty P_F dF = 1.0$$

- For this study option (i) has been adopted.
- P_O obtained from the following Table

CSC Flow Class (Alp *et al*, 1990) Page 11	# Events	P_O
Flow 1: Open hole - Casing flow	1	0.053
Flow 2: Combined flow	1	0.053
Flow 3: Annular flow	10	0.526
Flow 4: Drill pipe flow	7	0.368
Total	19	1.000

Note: Three blowouts outside of well bore not considered (Dunn/Holizki - 06/01/87)

- Frictional losses due to wellhead equipment are minimal relative to losses up the wellbore (Bissett 1986), thus $P_C = 1.0$, and is a default probability.

The following Table summarizes the probability of a potential emission rate, P(X1):

Flow Scenario	P_F	P_O	P_C	P(X1)
Flow 1	1.0	0.053	1.0	0.053
Flow 2	1.0	0.053	1.0	0.053
Flow 3	1.0	0.526	1.0	0.526
Flow 4	1.0	0.368	1.0	0.368

X2 Probability of a Potential Geometry.

- Release orientation (Horizontal versus Vertical) and release mode (Jet versus Cloud) data has been summarized for the majority of drilling blowouts for the 1976-86 period. See ERCB Volume 7.
- Identified in the Phase I report for this study (Alp *et al*, 1990) are four potential release geometries for well blowouts. The Table below summarizes probabilities for this event.

Geometry Type	# of Occurrences	P(X2)
Hor. Jet with wind	0.50	0.023
Hor. Jet into wind	0.50	0.023
Vertical Jet	13.00	0.590
Cloud	8.00	0.364
TOTAL	22.00	1.000

Note Three of the blowouts under the cloud situation ignited and later became vertical jets.

- Only one occurrence had a horizontal release. It is assumed that there is an equal chance of a horizontal jet pointing either upwind or downwind.

X3	Probability of a Potential Meteorology. • Joint probabilities of occurrence of the following parameters are determined: - wind speed - atmospheric stability - mixing height • Raw weather data to be gathered from the nearest Met. Station. P(X3) = 0.0628 for base case. (See Appendix E)
X4	Failure to Control Blow. • Probability of complete loss of control at a drilling well where it is not possible to shut the blowout preventers, or due to some sort of equipment failure. • The probability for this event is taken as the ratio of blowouts to blows. For the period 1975-88, 28 blowouts occurred from 62 blows. 5 sour blowouts from 90 blows and blowouts*** • The probability for this event is estimated as: $P(X4) = 5/90 = 5.56 \cdot 10^{-2}$
X5	Failure to Control Kick - Drilling With Diverter. • Data not sufficiently segregated to allow quantification of this event. • Occurrences falling in this category are likely taken into account in the general statistics. As a result, the probability for this event is taken as zero. P(X5) = 0.0
X6	Failure to Detect Kick (Pit Volume Increase) - Human Error. • A mud pit volume increase definitely indicates that a kick has been taken. • Human error is one possibility that contributes to failing to detect an increase in mud pit volume. Historical data is not sufficiently segregated to allow quantification of this event. An estimate general human error of omission (Henley and Kumamoto, 1981) can be used as a surrogate for this probability. The value is: $P(X6) = 1.0 \cdot 10^{-2}$ • The above probability is a general value. A more detailed approach using Human Error Analysis could be used to incorporate such factors as alarms and severe conditions.
X7	Depth Factor • modifying factor used to account for the difference in the probability of taking a kick with well depth. • The following correlation was established (BPRC, 1986): $F(K,d) = 0.0063 \cdot 10^{(d/3397)}$ where $F(K,d)$ = frequency of taking a kick per well drilled. d = depth of well (m) • The kick frequency base on global statistics is in Volume 7. $F(K) = 2918/83786 = 3.60 \cdot 10^{-2}$ kicks/total wells drilled (See Table A.1) • If n_a represents the number of kicks due to kick causal events that are influenced by depth and n_b the number that are not influenced by depth (need to segregate data), then: $M(X7) = R + (R\text{-}1)\, n_b/n_a$ where M(X7) = the depth modifying factor, and $R = F(K,d)/F(K)$ • A default value of M(X7) = 1.0 can be used as a default value.
X8	Failure to Detect Kick (Pit Volume Increase) - Equipment Failure. • A mud pit volume increase definitely indicates that a kick has been taken. • Equipment Failure is one possibility that contributes to failing to detect an increase in mud pit volume. Failure data for level measurement devices and alarms (faults/year) and inspection intervals need to be obtained, allowing a more detailed development of this event. • This event has not been quantified. Failure to control kick probability developed for event A5.

X9	Failure to Detect Kick (Flowing Well) - Equipment Failure. • A flowing well while the mud pump is off definitely indicates that a kick has been taken. • Equipment Failure is one possibility that contributes to failing to detect a flowing well. Failure data for flow measurement devices and alarms (faults/year) need to be obtained, allowing a more detailed development of this event. • This event has not been quantified. Failure to control kick probability developed for event A5.
X10	Insufficient Data Factor. • The quality of data available for a proposed well contributes to the likelihood of taking a kick as knowledge of expected hole integrity and formation pressure conditions enhances the ability to avoid well control problems. • To determine this modifier correlations of kick frequency versus Lahee classification (BPRC, 1986) or versus geologic information need to be developed. Available data could not support such an analysis. • The default value for this modifying factor is 1.0 M(X10) = 1.0
X11	Inflow Potential Factor. • Inflow potential increases the likelihood of a blow once a kick has been taken since the displacement of drilling fluid will be more rapid and extensive in a prolific well that in a non-prolific well. • This factor could be developed by correlating the frequency of blows (blows/kick) versus 0.5 log (Actual AOF/Normalized AOF). as suggested by the BPRC (1986). Available data was not sufficient to support such an analysis. • The default value for this modifying factor was 1.0. M(X11) = 1.0
X12	Failure to Shut-in Well - Improper Procedure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X13	Failure to Circulate Kick Out - Improper Procedure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X14	Failure to Shut-in Well - Choke(s) Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X15	Failure to Shut-in Well - Blowout Preventer Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X16	Failure to Shut-in Well - Drill Stem BOP Not Installed. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X17	Failure to Shut-in Well - Drill Stem BOP Inoperable. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X18	Failure to Circulate Kick Out - Flow Line Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X19	Failure to Circulate Kick Out - Gauge Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.

X20	Failure to Circulate Kick Out - Other Equipment Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
X21	Permeable Fluid Bearing Formation Encountered. • For a kick to be taken, a permeable fluid bearing formation would have been encountered. • The probability for this event must be 1.0 P(X21) = 1.0
X22	Kick While Tripping Out - Mud Density Too Low. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19.
X23	Kick While Tripping Out - Trip Swabbing. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19.
X24	Kick While Tripping Out - Extremely Permeable Formation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19.
X25	Kick While Tripping In - Weak Formation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping in kicks is quantified for event A20.
X26	Kick While Tripping In - Trip Surging. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping in kicks is quantified for event A20.
X27	Kick While Circulating - Problems From Previous Operation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of circulating kicks is quantified for event A21.
X28	Kick While Circulating - Mud Problems Operation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of circulation kicks is quantified for event A21.
X29	Kick While Tripping Out - Equipment Problems. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19.
X30	Kick While Tripping Out - Human Error. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19.
X31	Kick Taken While Testing. • Small fraction of kicks taken occur while testing. As a result, this event has not developed further. • $F(X31) = K_T / T = 89/83786$ $= 1.06 \cdot 10^{-03}$ kicks/well drilled where, K_T = Number of kicks taken while testing T = Number of conventional oil + gas wells drilled (1975-88)

X32	Kick Taken While Coring. • Small fraction of kicks taken occur while coring. As a result, this event has not developed further. • F(X32) = K_C / T = 110/83786 = $1.31 \cdot 10^{-3}$ kicks/well drilled where, K_{CO} = Number of kicks taken while coring T = Number of conventional oil + gas wells drilled (1975-88) ***
X33	Kick Taken While Running Casing. • Small fraction of kicks taken occur while running casing. As a result, this event has not developed further. • F(X33) = K_R / T = 58/83786 = $6.92 \cdot 10^{-4}$ kicks/well drilled where, K_R = Number of kicks taken while casing T = Number of conventional oil + gas wells drilled (1975-88)
X34	Kick Taken While Logging • Small fraction of kicks taken occur while logging. As a result, this event has not developed further. • F(X34) = K_L / T = 18/83786 = $2.15 \cdot 10^{-4}$ kicks/well drilled where, K_L = Number of kicks taken while logging T = Number of conventional oil + gas wells drilled (1975-88)
X35	Kick While Drilling - Mud Density Too Low. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X36	Kick While Drilling - Connection Swabbing. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X37	Kick While Drilling - Abnormal Formation Pressure. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X38	Kick While Drilling - Equipment Problems. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X39	Kick While Drilling - Human Error. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X40	Kick While Drilling - Mud Density Too High. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X41	Kick While Drilling - Pump Start-up. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.
X42	Kick While Drilling - Excessive Run-in Speed. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18.

X43	Primary Ignition Failure. • During well drilling operations it is assumed that an electronic ignition system will provide the primary ignition source. • Probability of primary ignition failure taken from Bercha Shell Bearberry (December, 1986): $P(X43) = 1.0 \cdot 10^{-2}$
X44	Secondary Ignition Failure. • During well drilling operations it is assumed that a shotgun flare system will provide the secondary ignition source. • Probability of secondary ignition failure taken from Bercha Shell Bearberry (December, 1986): $P(X44) = 5.0 \cdot 10^{-2}$
X45	Operator Error. • Probability of operator error taken from Henly and Kumamoto (1981): $P(X45) = 1.0 \cdot 10^{-2}$
A1	Sour Gas Release from a Well Blowout During Drilling For Given Emission Rate, Geometry and Meteorology. $F(A1) = F(A2) \cdot P(X1) \cdot P(X2) \cdot P(X3) \cdot P(A46) = 2.53 \cdot 10^{-9}$ in units of Events/Well Drilled
A2	Frequency of Occurrence of an Uncontrolled Sour Well Blowout. • from the Alberta statistics on all oil and gas wells the frequency of occurrence for this event can be calculated by: $F(A2) = F(A3) \cdot P(X4) \cdot N_{tot}/N_{sour}$ $= (1.07 \cdot 10^{-3})(5.56 \cdot 10^{-2})$ (7.6) $= 4.53 \cdot 10^{-4}$ sour blowouts/sourwell drilled
A3	Frequency of Occurrence of a Well Blow. $F(A3) = F(A4) \cdot F(A5)$ $= (3.48 \cdot 10^{-2})(3.08 \cdot 10^{-2})$ $= 1.07 \cdot 10^{-3}$ blows/well drilled

A4	Frequency of Occurrence of a Kick. $F(A4) = SUM\ F(A18\text{-}21) + SUM\ F(X31\text{-}34)$ $= 1.48 \cdot 10^{-2} + 1.19 \cdot 10^{-2} + 3.71 \cdot 10^{-3} + 9.79 \cdot 10^{-4}$ $+ 1.06 \cdot 10^{-3} + 1.31 \cdot 10^{-3} + 6.92 \cdot 10^{-4}$ $+ 2.15 \cdot 10^{-4}$ $= 3.48 \cdot 10^{-2}$ kicks/well drilled
A5	Probability for Failure to Control Kick. • Data insufficient to allow quantification of further developed subtree. • The probability for this event is estimated as the ratio of blows to kicks taken (1976-86). Thus: $P(A5) = 90/2918 = 3.08 \cdot 10^{-2}$ Blows/Kick
A6	Failure to Detect Kick (Modified by Depth Factor). • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A7	Ineffective Kick Handling (Modified by Insufficient Data and Inflow Potential Factor). • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A8	Failure to Detect Kick. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A9	Failure to Detect Pit Volume Increase While Mud Pump is on. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A10	Failure to Detect Kick While Mud Pump is Off. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A11	Ineffective Kick Handling. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A12	Failure to Detect Flowing Well While Mud Pump is Off. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A13	Failure to Detect Pit Volume Increase While Mud Pump is Off. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A14	Failure to Shut-in Well. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A15	Failure to Circulate Kick Out. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A16	Failure to Shut-in Well Due to Equipment Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.

A17	Failure to Circulate Kick Out Due to Equipment Failure. • Accident data not sufficiently segregated to allow quantification of this event. • Probability for failing to control kicks is quantified for event A5.
A18	Kick Taken While Drilling. • Accident data not sufficiently segregated to allow quantification of further developed subtree for this event. • F(A18) = K_D / T = 1239/83786 = $1.48 \cdot 10^{-2}$ kicks/well drilled where, K_D = Number of kicks taken while drilling T = Number of conventional wells drilled (1975-88)
A19	Kick Taken While Tripping Out. • Accident data not sufficiently segregated to allow quantification of further developed subtree for this event. • F(A19) = K_{TO} / T = 1000/83786 = $1.19 \cdot 10^{-2}$ kicks/well drilled where, K_{TO} = Number of kicks taken while tripping out T = Number of conventional wells drilled (1975-88)
A20	Kick Taken While Tripping In. • Accident data not sufficiently segregated to allow quantification of further developed subtree for this event. • F(A20) = K_{TI} / T = 311/83786 = $3.71 \cdot 10^{-3}$ kicks/well drilled where, K_{TI} = Number of kicks taken while tripping in T = Number of conventional wells drilled (1975-88)
A21	Kick Taken While Circulating. • Accident data not sufficiently segregated to allow quantification of further developed subtree for this event. • F(A21) = K_{CR} / T = 110/83786 = $9.79 \cdot 10^{-4}$ kicks/well drilled where, K_{CI} = Number of kicks taken while circulating T = Number of conventional wells drilled
A22	Kick While Tripping Out - Insufficient Borehole Pressure. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A22) = F(A25) + F(A26) + F(A27)
A23	Kick While Tripping In - Loss of Fluids To Formation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping in kicks is quantified for event A20. • If data were available, this event would be quantified by: F(A23) = F(A28) • F(A29)
A24	Kick While Circulating - Insufficient Borehole Pressure. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of circulating kicks is quantified for event A21. • If data were available, this event would be quantified by: F(A24) = F(X27) + F(X28)

A25	Kick While Tripping Out - Insufficient Mud Weight. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A25) = F(A30) + F(X22)
A26	Kick While Tripping Out - Trip Swabbing. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A26) = F(X23) • M(X7)
A27	Kick While Tripping Out - Loss of Fluids to Formation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A27) = F(X24) • M(X10)
A28	Kick While Tripping In - Weak Formation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping in kicks is quantified for event A20. • If data were available, this event would be quantified by: F(A28) = F(X25) • M(X10)
A29	Kick While Tripping In - Trip Surging. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping in kicks is quantified for event A20. • If data were available, this event would be quantified by: F(A29) = F(X26) • M(X7)
A30	Kick While Tripping Out - Failure to Keep Hole Full. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A30) = F(A31) + F(A32)
A31	Kick While Tripping Out - Equipment Problems. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A31) = F(X29) • M(X7)
A32	Kick While Tripping Out - Human Error. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of tripping out kicks is quantified for event A19. • If data were available, this event would be quantified by: F(A32) = F(X30) • M(X7)
A33	Kick While Drilling - Insufficient Borehole Pressure. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A33) = F(A34) + F(A35) + F(A36)
A34	Kick While Drilling - Insufficient Mud Weight. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A34) = F(A37) + F(A38) + F(X35)

A35	Kick While Drilling - Connection Swabbing. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A35) = F(X36) • M(X7)
A36	Kick While Drilling - Lost Circulation. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A36) = F(A39) + F(A40)
A37	Kick While Drilling - Unexpected Formation Pressure. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A37) = F(X37) • M(X10)
A38	Kick While Drilling - Failure to Keep Hole Full. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A38) = F(A41) + F(A42)
A39	Kick While Drilling - Formation Fractured. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A39) = F(A43) + F(A44)
A40	Kick While Drilling - Loss of Formation Fluids. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A40) = F(X24) • M(X10)
A41	Kick While Drilling - Equipment Problems. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A41) = F(X38) • M(X7)
A42	Kick While Drilling - Human Error. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A42) = F(X39) • M(X7)
A43	Kick While Drilling - Drilling. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A43) = F(A28) + F(X40)
A44	Kick While Drilling - Connection Surge. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: F(A44) = F(A45) + F(X41)

A45	Kick While Drilling - Excessive Run-in Speed. • Accident data not sufficiently segregated to allow quantification of this event. • Frequency of drilling kicks is quantified for event A18. • If data were available, this event would be quantified by: $F(A45) = F(X42) \cdot M(X7)$
A46	Non-Ignition of Uncontrolled Well Blowout. $P(A46) = P(A47) + P(X45)$ $= 5.0 \cdot 10^{-4} + 1.0 \cdot 10^{-2}$ $= 1.05 \cdot 10^{-2}$
A47	Ignition Failure. $P(A47) = P(X43) \cdot P(X44)$ $= 1.0 \cdot 10^{-2} \cdot 5.0 \cdot 10^{-2}$ $= 5.0 \cdot 10^{-4}$

APPENDIX C1

NON-DRILLING PRODUCING WELL FAULT TREE QUANTIFICATION PROCEDURE

C1.1 Non-Drilling Well Fault Tree

X1 — Probability of a Potential Emission Rate.

- Emission Rate depends upon

  (i) producing flow rate of well (deliverability), P_F
  (ii) whether the flow is up the tubing, annulus, tubing and annulus or open hole, P_O, and
  (iii) whether the flow is constricted by wellhead equipment (minimal), P_C.

  $P(X1) = P_F P_O P_C$

- Well deliverability is a site-specific parameter. For proposed wells two options are possible: (i) estimate risks for certain predefined potential flowrates where $P_F = 1.0$ and (ii) establish a frequency distribution of potential well deliverabilities either through statistical analysis or Monte Carlo simulation where:

$$\int_0^\infty P_F dF = 1.0$$

- for this study, option (i) has been adopted

- with $P_C = 1.0$ as described in Appendix B, and P_O from Appendix A the following are the values for this event box:

Flow Scenario	P(X1)
Flow 1 Casing Flow	0.171
Flow 2 Combined Flow	0.171
Flow 3 Annular Flow	0.171
Flow 4 Tubing Flow	0.487

X2 — Probability of a Potential Geometry.

- from Table A.7

Geometry	P(X2)
Horizontal Jet with wind	0.25
Horizontal Jet against wind	0.25
Vertical Jet	0.50
Cloud	0.00

X3 — Probability of a Potential Meteorology.

- Joint probabilities of occurrences of the following parameters are determined:
  - wind speed,
  - wind direction,
  - atmospheric stability,
  - mixing height.
- Raw weather data gathered from the nearest Met. station.
- P(X3) = 0.0628 for base case (see Appendix E).

X4 — Non-Ignition of Well Blowout During Normal Production.

- Under normal production, sour gas wells are unmanned.
- Zero probability of "quasi" - immediate ignition is assumed, thus:
  P(X4) = 1.0
- Hydrogen sulphide detectors surrounding the well lease can reduce detection time.

X5	Sour Gas Release During Normal Production due to Corrosion. • Accident data not segregated sufficiently to allow identification of corrosion caused producing well blowouts. • Frequency of Occurrence for this event is estimated by: $F(X5) = \frac{N_{EF} \cdot K_{NP} \cdot K_C}{T} = \frac{(3)(0.316)(0.714)}{17788}$ $= 3.80 \cdot 10^{-5}$ blowouts/(well•year) where N_{EF} = # equipment failure caused producing well blowouts for period over which data was gathered (1976-1986). (Dunn/Holizki - 22/04/87; Table 7A) K_{NP} = Fraction of Blowouts that occur during normal production. Ratio for producing gas wells assumed equal to that for non-drilling wells. (Dunn/Holizki - 21/04/87; Table 8) K_C = Fraction of equipment failures attributed to corrosion. (Bercha, Shell Bearberry - 12/86; Table A.1) $= \frac{2.5 \cdot 10^{-5} \text{ (corrosion)}}{3.5 \cdot 10^{-5} \text{ (equip. failure)}}$ T = Total number of sour well • years for period over which data was gathered. Sum of producing sour gas wells over years 1976-88
X6	Sour Gas Release During Normal Production due to Equipment Failure. • Same explanatory notes as for X5. • Frequency of Occurrence for this event estimated by: $F(X6) = \frac{N_{EF} \cdot K_{NP} \cdot K_{EF}}{T} = \frac{(3)(0.316)(0.286)}{17788}$ $= 1.52 \cdot 10^{-5}$ blowouts/(well•year) where K_{EF} = Fraction of equipment that are not corrosion related. $= \frac{7.0 \cdot 10^{-6}\text{(defect)} + 3.0 \cdot 10^{-6}\text{(design error)}}{3.5 \cdot 10^{-5}\text{(equip. failure)}}$ Bercha - Bearberry Dec, 1986, Table A1.
X7	Sour Gas Release During Normal Production due to Incorrect Procedures. • Accident data not segregated sufficiently to allow identification of normal production blowouts due to incorrect procedures. • Frequency of Occurrence for this event is estimated by: $F(X7) = \frac{N_{IP} \cdot K_{NP} K_O}{T} = \frac{(4)(0.316)(0.905)}{17788}$ $= 6.42 \cdot 10^{-5}$ blowouts/(well•year) where N_{IP} = # of incorrect procedure caused producing well blowouts for period over which data was gathered (1976-1989). K_{NP}, T as in X5. K_O = fraction of operator error estimated as incorrect procedures taken from (Bercha - Shell Bearberry, 1986; Table A.1) as $1.9 \cdot 10^{-5}/2.1 \cdot 10^{-1}$ $= 0.905$
X8	Sour Gas Release During Normal Production due to Incorrect Maintenance. • Accident data not sufficiently segregated to allow identification of this causal factor. • Frequency of occurrence for this event estimated by: $F(X8) = \frac{N_{IP} \cdot K_{NP}(1 - K_O)}{T} = \frac{(4)(0.316)(1 - 0.905)}{17788}$ $= 6.76 \cdot 10^{-6}$ blowouts/(well•year)

X9	Sour Gas Release During Normal Production due to Third Party Damage. • No sour gas releases during normal production have occurred due to third party damage. • Frequency of occurrence is non-zero and is estimated using failure statistics for all non-drilling sour wells. Only sour wells are used because greater precautionary measures are employed. • Frequency of occurrence for this event is estimated by: $F(X9) = \frac{\left(\frac{N_{TP,S}}{N_{TOT,S}}\right) \cdot N_{PR,S} \cdot K_{NP}}{T} = \frac{\left(\frac{1}{14}\right)(7)(0.316)}{17788}$ $= 8.88 \cdot 10^{-6}$ blowouts/(well•year) where $N_{TP,S}$ = # third party caused failures for all non-drilling sour wells. $N_{TOT,S}$ = # total failures for all non-drilling sour wells. $N_{PR,S}$ = # total failures for producing sour wells.
X10	Sour Gas Release During Normal Production due to Environment Accident. • No sour gas releases during normal production have occurred due to environmental accidents. • Frequency of occurrence is non-zero and is estimated using failure statistics for all non-drilling gas wells. • Frequency of occurrence for this event is estimated by: $F(X10) = \frac{\left(\frac{N_{EA}}{N_{TOT}}\right) \cdot N_{PR,S} \cdot K_{NP}}{T} = \frac{\left(\frac{2}{82}\right)(7)(0.316)}{17788}$ $= 3.03 \cdot 10^{-6}$ blowouts/(well•year) where N_{EA} = # environmental accident caused failures for all non-drilling wells. N_{TOT} = # total failures for all non-drilling wells.
X11	Failure to Control Release due to Operator Error. • This event covers such failures as (i) SSSV improperly installed or not installed, (ii) failure to close master valve - operator not wearing protective equipment and is overcome • A general human failure probability is assumed (Bercha - Shell Bearberry, Dec, 1986). $P(X11) = 1.0 \cdot 10^{-2}$

X12	Sub-Surface Safety Valve Failure (SSSV) • The following failure statistics were gathered by Calgary Area Office in Sour Gas Safety Study - 30/04/86): Number of Tests 780 Incomplete Valve Closures 1.6% • Assuming a 2 month inspection interval, τ, (Ref. Questionnaire) the valve failure rate (λ) can be estimated by: $$\lambda = \frac{\#\text{ failures}}{\#\text{ years service}} = \frac{(780)(.0071)}{(780)\left(\frac{1}{12}\right)}$$ $$= 0.085 \frac{\text{failures}}{\text{year}}$$ • The Mean Time To Failure (MTTF = 1/2) = 3800 days which is in good agreement with Sintef, 1986. The fractional down time (F_{DT}), which is the probability of failure per demand is given by Kletz (1986): $$F_{DT} = P(X12) = \frac{1}{2}\lambda\tau = \frac{1}{2}(0.096)\left(\frac{2}{12}\right)$$ $$= \frac{1}{2}(.085)\left(\frac{1}{12}\right) = 3.5 \cdot 10^{-3}$$
X13	Incorrect SSSV Setting. • A general human failure probability is assumed (Bercha - Shell Bearberry,, Dec. 1986). P(X13) = $1.0 \cdot 10^{-2}$
X14	SSSV Control System Failure. • CanOxy reported No Instrumentation Failure. • Shell experience reported by Bercha - Shell Bearberry, (Dec, 1986) is used for this probability. P(X14) = $2.6 \cdot 10^{-3}$
X15	Frequency of Wireline Operations. • Well failure rate due to wireline work needs to be quantified on a per wireline operation basis yielding units: blowouts/wireline operation (R_{WL}). In order to determine frequency of occurrence in blowouts/(well•year) (F_{WL}), the above failure rate must be multiplied by the frequency of wireline operations in operations/(well•year) (S_{WL}). Thus, $F_{WL} = R_{WL} S_{WL}$, where S_{WL} = F(X15) • Bercha - Shell Bearberry, (December, 1986) suggests S_{WL} = 1.0 operations/(well•year) as an industry average. • Accident data is not sufficiently segregated to allow a more detailed analysis. Servicing failures will be quantified for event A5 based on the limited breakdown of data available.
X16	Frequency of Workover Operations. • Same approach is required as for frequency of wireline operations. • $F_{WO} = R_{WO} S_{WO}$, where S_{WO} = F(X16) • Bercha - Shell Bearberry, (December, 1986) suggests S_{WO} = 0.20 operations/(well•year) • Accident data is not sufficiently segregated to allow a more detailed analysis. Servicing failures will be quantified for event A5 based on the limited breakdown of data available.
X17 X18 X19 X20 X21 X22	• Frequencies of occurrence for all these events were not extractable from the limited breakdown of data available. • Servicing related failures will be accounted for in event A5 • Quantification of these events would be accomplished by dividing the number of failures by the total number of operations for the time period over which the data was gathered.

X23	Failure to Ignite Sour Gas Release due to Igniter(s) Failure. • It is assumed that the only ignition system available during servicing operations on producing wells is a flare gun system. • Failure probability for this igniter system is taken from Bercha - Shell Bearberry, (December, 1986). $P(X23) = 5.0 \cdot 10^{-2}$
X24	Failure to Ignite Sour Gas Release due to Operator Error. • Failure probability for this event is taken from Bercha - Shell Bearberry, (December, 1986). $P(X24) = 1.0 \cdot 10^{-3}$
A1	Frequency of Occurrence of an Uncontrolled Sour Gas Release from a Producing Well for Given Emission Rate, Geometry and Meteorology. $F(A1) = F(A2) \cdot P(X1) \cdot P(X2) \cdot P(X3) = 1.32 \cdot 10^{-7}$
A2	Frequency of Occurrence of an Uncontrolled Sour Gas Release from a Producing Well. $F(A2) = F(A3) + F(A4)$ $= 3.55 \cdot 10^{-6} + 1.37 \cdot 10^{-5}$ $= 1.73 \cdot 10^{-5}$ blowouts/(well•year)
A3	Frequency of Occurrence of an Uncontrolled Sour Gas Release During Normal Production. $F(A3) = F(A6) \cdot P(A7) \cdot P(X4)$ $= (1.36 \cdot 10^{-4})(2.61 \cdot 10^{-2})(1.0)$ $= 3.55 \cdot 10^{-6}$ blowouts/(well•year)
A4	Frequency of Occurrence of an Uncontrolled Sour Gas Release During Servicing. $F(A4) = F(A5) \cdot P(A14)$ $= (2.69 \cdot 10^{-4})(5.1 \cdot 10^{-2})$ $= 1.37 \cdot 10^{-5}$ blowouts/(well•year)
A5	Frequency of Occurrence of a Sour Gas Release During Servicing • Accident data not segregated sufficiently to allow a further breakdown of this event. • Frequency of Occurrence for this event is estimated by: $F(A5) = \frac{N_{PR,S}(1-K_{NP})}{T} = \frac{7(1-0.316)}{17788}$ $= 2.69 \cdot 10^{-4}$ blowouts/(well•year) • If further segregation were quantifiable, $F(A5) = F(A8) + F(A9)$
A6	Frequency of Occurrence of a Sour Gas Release During Normal Production. $F(A6) = F(A10) + F(A11)$ $= 1.24 \cdot 10^{-4} + 1.19 \cdot 10^{-5}$ $= 1.36 \cdot 10^{-4}$ blowouts/(well•year)
A7	Probability for Failure to Control a Release. $P(A7) = P(A12) + P(X11)$ $= 1.61 \cdot 10^{-2} + 1.0 \cdot 10^{-2}$ $= 2.61 \cdot 10^{-2}$
A8	Frequency of Occurrence of a Sour Gas Release During Wireline Work. • Accident data is not sufficiently segregated so that this event can be quantified. • The required approach is indicated in the explanatory notes for event X16, thus: $F(A8) = [F(X18) + F(X19)] \cdot F(X16)$ in units of blowouts/(well•year)
A9	Frequency of Occurrence of a Sour Gas Release During Workovers. • Same explanatory notes as above and event X17 $F(A9) = [F(X20) + F(X21) + F(A15)] \cdot F(X17)$ in units of blowouts/(well•year)

A10	Frequency of Occurrence of a Sour Gas Release During Normal Production due to Operations at Well. $F(A10) = F(X5) + F(X6) + F(A13)$ $= 3.08 \cdot 10^{-5} + 1.52 \cdot 10^{-5} + 7.10 \cdot 10^{-5}$ $= 1.24 \cdot 10^{-4}$ blowouts/(well•year)
A11	Frequency of Occurrence of a Sour Gas Release During Normal Production due to Operations at Well. $F(A11) = F(X9) + F(X10)$ $= 8.88 \cdot 10^{-6} + 3.03 \cdot 10^{-6}$ $= 1.19 \cdot 10^{-5}$ blowouts/(well•year)
A12	SSSV Unavailability. • This event represents the probability that the SSSV will not close when demanded. $P(A12) = P(X12) + P(X13) + P(X14)$ $= 3.5 \cdot 10^{-3} + 1.0 \cdot 10^{-2} + 2.6 \cdot 10^{-3}$ $= 1.61 \cdot 10^{-2}$
A13	Frequency of Occurrence of a Sour Gas Release During Normal Production due to Human Error. $F(A13) = F(X7) + F(X8)$ $= 6.42 \cdot 10^{-5} + 6.76 \cdot 10^{-6}$ $= 7.10 \cdot 10^{-5}$ blowouts/(well•year)
A14	Non-Ignition of Sour Gas Release During Servicing. $P(A14) = P(X23) + P(X24)$ $= 5.0 \cdot 10^{-2} + 1.0 \cdot 10^{-3}$ $= 5.1 \cdot 10^{-2}$ (Bercha - Shell Bearberry, Dec 1986)
A15	Frequency of Occurrence of a Sour Gas Release During Workover due to Human Error. • Same explanatory notes as for event A9. • If lower events could be quantified, then, $F(A15) = F(X22) + F(X23)$ in units of blowouts/workover operation (Bercha - Shell Bearberry, Dec 1986)

APPENDIX C2

NON-DRILLING, NON-PRODUCING WELL FAULT TREE QUANTIFICATION PROCEDURE

C2.1 Non-Drilling, Non-Producing Well Fault Tree

X1 — Probability of a Potential Emission Rate.

- Emission Rate depends upon

  (i) producing flow rate of well (deliverability), P_F
  (ii) whether the flow is up the tubing, annulus, tubing and annulus or open hole, P_O, and
  (iii) whether the flow is constricted by wellhead equipment (minimal), P_C.

  $P(X1) = P_F P_O P_C$

- Well deliverability is a site-specific parameter. For proposed wells two options are possible: (i) estimate risks for certain predefined potential flowrates where $P_F = 1.0$ and (ii) establish a frequency distribution of potential well deliverabilities either through statistical analysis or Monte Carlo simulation where:

$$\int_0^\infty P_F dF = 1.0$$

- for this study, option (i) has been adopted

- with $P_C = 1.0$ as described in Appendix B, and P_O from Appendix A the following are the values for this event box:

Flow Scenario	P(X1)
Flow 1 Casing Flow	0.33
Flow 2 Combined Flow	0.33
Flow 3 Annular Flow	0
Flow 4 Tubing Flow	0.34

X2 — Probability of a Potential Geometry.

- from Table A.7

Geometry	P(X2)
Horizontal Jet with wind	0.25
Horizontal Jet against wind	0.25
Vertical Jet	0.50
Cloud	0.00

X3 — Probability of a Potential Meteorology.

- Joint probabilities of occurrences of the following parameters are determined:
  - wind speed,
  - atmospheric stability,
  - mixing height.
- Raw weather data gathered from the nearest Met. station.
- P(X3) = 0.0628 for base case (see Appendix E).

X4 — Non-Ignition of Well Blowout During Normal Production.

- Under normal production, sour gas wells are unmanned.
- Zero probability of "quasi" - immediate ignition is assumed, thus:
  P(X4) = 1.0
- Hydrogen sulphide detectors surrounding the well lease can reduce detection time.

X5	Sour Gas Release From Non-Producting Wells due to Corrosion. • Accident data not segregated sufficiently to allow identification of corrosion caused producing well blowouts. • Frequency of Occurrence for this event is estimated by: $F(X5) = \frac{N_{EF} \cdot K_C}{T} = \frac{(5)(.714)}{45461}$ $= 7.86 \cdot 10^{-5}$ blowouts/(well•year) where N_{EF} = # equipment failure caused non-producing well blowouts for period over which data was gathered (1976-1988). K_C = Fraction of equipment failures attributed to corrosion. (Bercha, Shell Bearberry - 12/86; Table A.1) $= \frac{2.5 \cdot 10^{-5} \text{ (corrosion)}}{3.5 \cdot 10^{-5} \text{ (equip. failure)}}$ T = Total number of sour well • years for period over which data was gathered.
X6	Sour Gas Release During Normal Production due to Equipment Failure. • Same explanatory notes as for X5. • Frequency of Occurrence for this event estimated by: $F(X6) = \frac{N_{EF} \cdot K_{EF}}{T} = \frac{(5)(0.286)}{45461}$ $= 3.14 \cdot 10^{-5}$ blowouts/(well•year) where K_{EF} = Fraction of equipment that are not corrosion related. $= \frac{7.0 \cdot 10^{-6}\text{(defect)} + 3.0 \cdot 10^{-6}\text{(design error)}}{3.5 \cdot 10^{-5}\text{(equip. failure)}}$ Bercha - Bearberry Dec, 1986, Table A1.
X7	Sour Gas Release Non-Producing due to Incorrect Procedures. • Accident data not segregated sufficiently to allow identification of normal production blowouts due to incorrect procedures. • Frequency of Occurrence for this event is estimated by: $F(X7) = \frac{N_{IP} \cdot K_O}{T} = \frac{(1)(0.905)}{45461}$ $= 1.99 \cdot 10^{-5}$ blowouts/(well•year) where N_{IP} = # of incorrect procedure caused producing well blowouts for period over which data was gathered (1976-1989). K_O = fraction of operator error estimated as incorrect procedures taken from (Bercha - Shell Bearberry, 1986; Table A.1) as $1.9 \cdot 10^{-5} / 2.1 \cdot 10^{-1}$ $= 0.905$
X8	Sour Gas Release During Normal Production due to Incorrect Maintenance. • Accident data not sufficiently segregated to allow identification of this causal factor. • Frequency of occurrence for this event estimated by: $F(X8) = \frac{N_{IP} \cdot (1 - K_O)}{T} = \frac{(1)(1 - 0.905)}{45461}$ $= 2.09 \cdot 10^{-6}$ blowouts/(well•year)

X9	Sour Gas Release During Normal Production due to Third Party Damage. • No sour gas releases during normal production have occurred due to third party damage. • Frequency of occurrence is non-zero and is estimated using failure statistics for all non-drilling sour wells. Only sour wells are used because greater precautionary measures are employed. • Frequency of occurrence for this event is estimated by: $F(X9) = \left(\frac{N_{TP,S}}{N_{TOT,S}}\right) \cdot \frac{N_{PR,S}}{T} = \frac{\left(\frac{1}{14}\right)(7)(0.316)}{45461}$ $= 2.20 \cdot 10^{-5}$ blowouts/(well•year) where $N_{TP,S}$ = # third party caused failures for all non-drilling sour wells. (Table A.4) $N_{TOT,S}$ = # total failures for all non-drilling sour wells. (Table A.4) $N_{PR,S}$ = # total failures for producing sour wells. (Table A.4)
X10	Sour Gas Release During Normal Production due to Environment Accident. • No sour gas releases during normal production have occurred due to environmental accidents. • Frequency of occurrence is non-zero and is estimated using failure statistics for all non-drilling gas wells. • Frequency of occurrence for this event is estimated by: $F(X10) = \left(\frac{N_{EA}}{N_{TOT}}\right) \cdot \frac{N_{PR,S}}{T} = \frac{\left(\frac{2}{82}\right)(7)(0.316)}{45461}$ $= 3.76 \cdot 10^{-6}$ blowouts/(well•year) where N_{EA} = # environmental accident caused failures for all non-drilling wells. (Table A.4) N_{TOT} = # total failures for all non-drilling wells. (Table A.4)
X11	Failure to Control Release due to Operator Error. • This event covers such failures as (i) SSSV improperly installed or not installed, (ii) failure to close master valve - operator not wearing protective equipment and is overcome • A general human failure probability is assumed (Bercha - Shell Bearberry, Dec, 1986). $P(X11) = 1.0 \cdot 10^{-2}$

X12	****** Sub-Surface Safety Valve Failure (SSSV) • The following failure statistics were reported by CanOxy (Fountain/Havelock - 26/03/87): Number of Tests 243 Incomplete Valve Closures 1.6% • Assuming a 2 month inspection interval, τ, (Ref. Questionnaire) the valve failure rate (λ) can be estimated by: $$\lambda = \frac{\#\text{ failures}}{\#\text{ years service}} = \frac{(780)(.007)}{(780)\left(\frac{1}{12}\right)}$$ $$= 0.085 \frac{\text{failures}}{\text{year}}$$ • The Mean Time To Failure (MTTF = 1/2) = 3800 days which is in good agreement with Sintef, 1986. The fractional down time (F_{DT}), which is the probability of failure per demand is given by Kletz (1986): $$F_{DT} = P(X12) = \frac{1}{2}\lambda\tau = \frac{1}{2}(0.085)\left(\frac{1}{12}\right)$$ $$= 3.5 \cdot 10^{-3}$$
X13	Incorrect SSSV Setting. • A general human failure probability is assumed (Bercha - Shell Bearberry, Dec. 1986). P(X13) = $1.0 \cdot 10^{-2}$
X14	SSSV Control System Failure. • Shell experience reported by Bercha - Shell Bearberry, (Dec, 1986) is used for this probability. P(X14) = $2.6 \cdot 10^{-3}$
X15	Frequency of Wireline Operations. • Not Applicable to Non-Producing
X16	Frequency of Workover Operations. • Not Applicable to Non-Producing
X17 X18 X19 X20 X21 X22	• Not Applicable to Non-Producing
X23	Failure to Ignite Sour Gas Release due to Igniter(s) Failure. • It is assumed that the only ignition system available during servicing operations on producing wells is a flare gun system. • Failure probability for this igniter system is taken from Bercha - Shell Bearberry, (December, 1986). P(X23) = $5.0 \cdot 10^{-2}$
X24	Failure to Ignite Sour Gas Release due to Operator Error. • Failure probability for this event is taken from Bercha - Shell Bearberry, (December, 1986). P(X24) = $1.0 \cdot 10^{-3}$

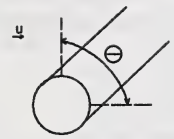
A1	Frequency of Occurrence of an Uncontrolled Sour Gas Release from a Non-Producing Well for Given Emission Rate, Geometry and Meteorology. $F(A1) = F(A2) \cdot P(X1) \cdot P(X2) \cdot P(X3) = 2.20 \cdot 10^{-8}$
A2	Frequency of Occurrence of an Uncontrolled Sour Gas Release from a Non-Producing Well. $F(A2) = F(A3) + F(A4)$ $= 4.12 \cdot 10^{-6} + 0$ $= 4.12 \cdot 10^{-6}$ blowouts/(well•year)
A3	Frequency of Occurrence of an Uncontrolled Sour Gas Release From a Non-Producing Well. $F(A3) = F(A6) \cdot P(A7) \cdot P(X4)$ $= (1.58 \cdot 10^{-4})(2.61 \cdot 10^{-2})(1.0)$ $= 4.12 \cdot 10^{-6}$ blowouts/(well•year)
A4	Frequency of Occurrence of an Uncontrolled Sour Gas Release During Servicing. • Not Applicable to Non-Producing
A5	Frequency of Occurrence of a Sour Gas Release During Servicing • Not Applicable to Non-Producing
A6	Frequency of Occurrence of a Sour Gas Release From a Non-Producing Well. $F(A6) = F(A10) + F(A11)$ $= 1.32 \cdot 10^{-4} + 2.58 \cdot 10^{-5}$ $= 1.58 \cdot 10^{-4}$ blowouts/(well•year)
A7	Probability for Failure to Control a Release. $P(A7) = P(A12) + P(X11)$ $= 1.61 \cdot 10^{-2} + 1.0 \cdot 10^{-2}$ $= 2.61 \cdot 10^{-2}$
A8	Frequency of Occurrence of a Sour Gas Release During Wireline Work. • Not Applicable to Non-Producing
A9	Frequency of Occurrence of a Sour Gas Release During Workovers. • Not Applicable to Non-Producing
A10	Frequency of Occurrence of a Sour Gas Release During Normal Production due to Operations at Well. $F(A10) = F(X5) + F(X6) + F(A13)$ $= 7.86 \cdot 10^{-5} + 3.14 \cdot 10^{-5} + 2.20 \cdot 10^{-5}$ $= 1.32 \cdot 10^{-4}$ blowouts/(well•year)
A11	Frequency of Occurrence of a Sour Gas Release During Normal Production due to External Accident. $F(A11) = F(X9) + F(X10)$ $= 2.20 \cdot 10^{-5} + 3.76 \cdot 10^{-6}$ $= 2.58 \cdot 10^{-5}$ blowouts/(well•year)
A12	SSSV Unavailability. • This event represents the probability that the SSSV will not close when demanded. $P(A12) = P(X12) + P(X13) + P(X14)$ $= 3.5 \cdot 10^{-3} + 1.0 \cdot 10^{-2} + 2.6 \cdot 10^{-3}$ $= 1.61 \cdot 10^{-2}$
A13	Frequency of Occurrence of a Sour Gas Release During Normal Production due to Human Error. $F(A13) = F(X7) + F(X8)$ $= 1.99 \cdot 10^{-5} + 2.09 \cdot 10^{-6}$ $= 2.20 \cdot 10^{-5}$ blowouts/(well•year)

A14	Non-Ignition of Sour Gas Release During Servicing. $P(A14) = P(X23) + P(X24) = 5.10 \cdot 10^{-3}$
A15	Frequency of Occurrence of a Sour Gas Release During Workover due to Human Error. • Not Applicable to Non-Producing

APPENDIX D

PIPELINE FAULT TREE QUANTIFICATION PROCEDURE FOR RUPTURES AND LEAKS

D1.1 Pipeline Fault Tree - Ruptures

X1	Probability of a Potential Geometry.  • Geometry defined in terms of angle normal to wind direction. • Current database does not allow detailed quantification of this probability. • For surface release horizontal jet geometry assumed since this is the worst case and P(X1) = 0.5 for both upwind jet and downwind jet. • For a subsurface release cloud geometry assumed, with P(X1) = 1.0.
X2	Probability of a Potential Meteorology. • Joint probabilities are determined in terms of the following parameters. • surface heat flux for stable and unstable atmospheres • wind speed • wind direction • atmospheric stability • mixing height for unstable atmospheres • Raw weather data gathered from the nearest Met. Station. • P(X2) = 0.0628 from processed data for base case (see Appendix E).
X3	Non - Ignition. • Quasi - immediate ignition following a pipeline rupture very rare according to historical information. • P(X3) = 1.0 (conservative).
X4	Probability of a Potential Hole Size. • 8 ruptures categorized as short ruptures and 1 rupture is long rupture (rupture definitions in Volume 5 report). • from above data, P(X4) = 0.89 for short ruptures (32%) of opening and P(X4) = 0.11 = $1.1 \cdot 10^{-1}$ for long ruptures (100% of opening). Table A.9.
X5	Miscellaneous other Ruptures. • One such identified rupture has occurred over approximately (47400 km•year) of sour gas pipeline service (1975-1989). • F(X5) = 1/(47400 km•year) = $2.11 \cdot 10^{-5}$ ruptures/(km•year)
X6	Third Party Damage to ESD Valves. • No known incidences of this type have occurred over the time period from which data was gathered. • Since these installations are above ground, they are not prone to accidental third party damage. • $P(X6) = \frac{1}{2}\lambda\tau = \frac{(8.1 \cdot 10^{-4})\left(\frac{2}{12}\right)}{2}$ $= 6.75 \cdot 10^{-5}$

X7	ESD Valve Unavailable due to Operator Error. • Bercha - Shell Bearberry, (Dec, 1986) gives the following rate, λ^*, for ESD Valve failure due to Operator Error: $\lambda^* = 5.0 \cdot 10^{-3}$ failures/demand • Assuming an inspection interval of 2 months (τ) (Ref: CanOxy 1 CSC 10/06/87), the failure rate, λ, expressed in terms of failures per year can be calculated by: $\lambda = \lambda^* N^*$, where N^* = # of tests per year $= (5.0 \cdot 10^{-3})(6) = 3.0 \cdot 10^{-2}$ failures/year The desired approach would be: The fractional down time (F_{DT}) for the value due to operator error, which is the probability of failure per demand is given by Kletz (1986) as: $F_{DT} = \frac{1}{2}\lambda\tau = \frac{(3.0 \cdot 10^{-2})\left(\frac{2}{12}\right)}{2}$ $= 2.5 \cdot 10^{-3}$
X8	ESD Valve Failure due to Valve Defect. • Reliable failure data for these values in sour gas service was not available. • General failure data for pneumatic actuators obtained from Henley and Kimamoto (1981). • Probability for this event taken into account for event A6.
X9	ESD Valve Failure due to Control System Failure. • Same explanatory notes as for event X8.
X10	Rupture of Buried Pipe due to Inadequate Pipe Material Leading to Corrosion. • No recorded failures due to this causal factor for time period over which data was gathered (15 years). • Incident rate is non-zero and lies between 0 and 1 in 15 years. • Since quality control procedures are high for sour gas service, incident rate is expected to be low. • 0.1 ruptures per 15 years is assumed as an incident rate for this event. • The frequency of occurrence is then estimated as: F(X10) = 0.1 ruptures/(47400 km•year) = $2.11 \cdot 10^{-6}$ ruptures/(km•year)
X11	Ruptures of Buried Pipe due to Corrosion at Girth or Fillet Weld. • No recorded failures due to this causal factor for time period over which data was gathered (15 years). • Again, incident rate is non-zero and lies between 0 and 1 in 15 years. • Welds are discontinuities along the pipeline and are likely corrosion initiation points. Incidence data does not reflect this. Lack of sufficient detail in reporting could have led to weld corrosion failures reported as internal corrosion. • 0.5 ruptures per 15 years is assumed as an incident rate for this event. • The frequency of occurrences is then estimated as: F(X11) = 0.5 ruptures/(47400 km•year) = $1.05 \cdot 10^{-5}$ ruptures/(km•year)
X12	Rupture of Buried Pipeline due to No Chemical Control Leading to Internal Corrosion. • Data on Internal Corrosion failures does not allow further segregation. More detailed reporting and analysis would be required. • Internal corrosion frequency estimated for event A17 based on reported internal corrosion failures and km • year of sour pipeline service.
X13	Rupture of Buried Pipeline due to Water in Gas Stream Leading to Internal Corrosion. • Same explanatory notes as for X12.

X14	Rupture of Buried Pipeline due to Line Heater Failure leading to Internal Corrosion. • Same explanatory notes as for X12.
X15	Rupture of Buried Pipeline due to Insufficient Gas Velocity leading to Internal Corrosion. • Same explanatory notes as for X12.
X16	Rupture of Buried Pipeline due to Inadequate Cathodic Protection Leading to External Corrosion. • Data on Internal Corrosion cannot be further segregated. More detailed reporting and analysis would be required. • External corrosion frequency estimated for event A20 based on reported external corrosion failures and km • year of sour gas pipeline service.
X17	Rupture of Buried Pipeline due to Surface Coating Deteriorated Leading to External Corrosion. • Same explanatory notes as for X16.
X18	Rupture of Buried Pipeline due to Improper Application of Surface Coating Leading to External Corrosion. • Same explanatory notes as for X16.
X19	Rupture of Buried Pipe due to Earth Movement. • No recorded failures due to this causal factor over 15 years • 0.5 ruptures in 15 years is assumed as an incident rate for this event. • The frequency of occurrence is then estimated as: $F(X19) = 0.5/(47400\ km \cdot year) = 1.05 \cdot 10^{-5}$ ruptures/(km•year)
X20	Rupture of Buried Pipe due to Third Party Damage. • 3 ruptures reported due to this cause. See Table A.5 • Frequency of Occurrence is estimated as: $F(X20) = 3$ ruptures/$(47400\ km \cdot year) = 6.33 \cdot 10^{-5}$ ruptures/(km•year)
X21	Rupture of Buried Pipe Due to Construction Damage. • 2 ruptures reported due to this cause. See Table A.5 • Frequency of Occurrence is estimated as: $F(X21) = 2$ ruptures/$(47400\ km \cdot year) = 4.22 \cdot 10^{-5}$ ruptures/(km•year)
X22	Rupture of Buried Pipe due to Overpressure. • 2 ruptures reported due to this cause. See Table A.5 • Frequency of occurrence is estimated as: $F(X22) = 2$ ruptures/$(47400\ km \cdot year) = 4.22 \cdot 10^{-5}$ ruptures/(km•year)
X23	Rupture of Buried Pipe due to Operator Error. • 1 rupture reported due to this cause. See Table A.5 • Frequency of Occurrence is estimated as: $F(X23) = 1$ rupture/$(47400\ km \cdot year) = 2.11 \cdot 10^{-5}$ ruptures/(km•year)

X24	Rupture of Buried Pipe due to Weld Failure. • 2 ruptures reported due to this cause. See Table A.5 • Frequency of occurrence is estimated as: F(X24) = 2 ruptures/(47400 km•year) = $4.22 \cdot 10^{-5}$ ruptures/(km•year)
X25	Rupture of Buried Pipe due to Excessive Stress causing Pipe Failure. • Analysis of reports on ruptures due to pipe failures indicate all failures can be attributed to excessive stress. • 10 ruptures were reported due to Pipe failure. See Table A.5 • Frequency of Occurrence is estimated as: F(X25) = 9 ruptures/(47400 km•year) = $2.11 \cdot 10^{-4}$ ruptures/(km•year)
X26	Rupture of Buried Pipe due to Installation of Wrong Pipe Material. • Due to the current required quality control procedures, expect this frequency to be very low. • Frequency of Occurrence can be synthesized from the number of pipe installations over the 15 year period and the probability of wrong installation. • (i) Number of installations • It is assumed that each installation of new pipe has an average length of 2.7 km. • Length of new pipe installed over 15 year period is approximately 4000 km (5500-1500). • Thus 1500 installations are assumed. • (ii) Probability of Incorrect Pipe/Pipe material being installed is $6.3 \cdot 10^{-5}$. • The above probability is the product of probabilities of human error during (a) design (0.025), (b) installation (0.05), and (c) Inspection (0.05). (Sandia, 1983) • The synthesized number of failures is 0.094. • The frequency of occurrence is estimated as: F(X26) = 0.094 ruptures/(47400 km•year) = $1.98 \cdot 10^{-6}$ ruptures/(km•year)

X27	Rupture of Surface Equipment Due to Internal Corrosion. • No recorded failures due to this causal factor over 15 year period. • Failure frequency is non-zero and is assumed to be 5% of that for Internal Corrosion of buried pipe: $F(X27) = 6.35 \cdot 10^{-6}$ ruptures/(km•year) • This seems to be an adequate assumption since only approximately 1% of total sour gas pipeline length is above ground but the discontinuities due to surface equipment will increase the likelihood of corrosion. • For the sour gas pipeline network, surface equipment (SE) are classified as ESD valves, Block Valves, Check Valves, Line heaters and compressors. • Each Sour gas well (> 1.00 H_2S is assumed to have an ESD and one line heater or compressor. • Number of SE's determined as follows. Number of km of Sour Pipeline (Verified to 1986) = 5500 km Number of Sour Wells = 1936 (1) Number of Wellhead ESD's = 1936 (2) Number of Line heaters or Compressors = 1936 (3) Number of Main line ESD's = $5500 \cdot \frac{73}{688}$ = 584 (4) Number of Check Valves = $\frac{\left(\frac{5500}{688}+\frac{1936}{223}\right)}{2} \cdot 169$ = 1409 Total of 1, 2, 3 + 4 = 5865 • Number of SE's per km $\rho_{SE} = \frac{5865}{5500} = 1.07 \frac{SE's}{km}$ • Then $F(X27) = 6.35 \cdot 10^{-6}$ ruptures/(km•year)• $\frac{1}{1.07} \frac{km}{SE}$ $= 5.92 \cdot 10^{-6}$ ruptures/(SE•year) Ratio of ESD's & check valves to length of ESD's of pipeline and wells ESD's, see Table A.8.
X28	Rupture of Surface Equipment due to External Corrosion. • Same explanatory notes as for X27. • $F(X28) = 3.17 \cdot 10^{-6}$ ruptures/(km•year) $= 2.96 \cdot 10^{-6}$ ruptures/(SE•year)
X29	Rupture of Surface Equipment due to Construction Damage. • Same explanatory notes as for X27. • $F(X29) = 2.10 \cdot 10^{-6}$ ruptures/(km•year) $= 1.97 \cdot 10^{-6}$ ruptures/(SE•year)
X30	Rupture of Surface Equipment Due to Third Party Damage • No recorded failures for this causal factor over 15 year period. • Same explanatory notes as for X27. • $F(X30) = 3.17 \cdot 10^{-6}$ ruptures/(km•year) $= 2.96 \cdot 10^{-6}$ ruptures/(SE•year)
X31	Rupture of Surface Equipment due to Earth Movement. • No recorded failures for this causal factor over 15 year period. • Same explanatory notes as for X27. • $F(X30) = 5.28 \cdot 10^{-7}$ ruptures/(km•year) $= 4.93 \cdot 10^{-7}$ ruptures/(SE•year)

X32	Rupture of Surface Equipment due to Failure of an Installation. • No recorded failures for this causal factor over 15 year period. • Frequency of occurrence is non-zero. This event would account for spontaneous failures. • 1.8% of leaks were attributed to this cause. Same ratio is assumed to apply to ruptures, result in an incident rate of 0.5 ruptures for the 15 years period. • The frequency of occurrence is then estimated as: $F(X32) = 0.5$ ruptures/(47400 km•year) $= 1.1 \cdot 10^{-5}$ ruptures/(km•year) $= 9.86 \cdot 10^{-6}$ ruptures/(SE•year)
X33	Ruptures of Surface Equipment due to Weld Failures. • Same explanatory notes as for X27. • $F(X33) = 2.1 \cdot 10^{-6}$ ruptures/(km•year) $= 1.97 \cdot 10^{-6}$ ruptures/(SE•year)
X34	Rupture of Surface Equipment due to Incorrect Installation of a Valve/Fitting. • Data on Valve/Fitting failures cannot be segregated further. • Valve/Fitting failure frequency estimated for event A23, based on Valve/Fitting failures and km • year of sour pipeline service.
X35	Rupture of Surface Equipment due to Inadequate Valve/Fitting Material. • Same notes as for X34.
X36	Rupture of Surface Equipment due to Damaged Valve/Fitting. • Same notes as for X35.
X37	Rupture of Surface Equipment due to Installation of Wrong Pipe Material. • Same notes as for X27. • $F(X37) = 9.90 \cdot 10^{-8}$ ruptures/(km•year) $= 9.27 \cdot 10^{-8}$ ruptures/(SE•year)
X38	Rupture of Surface Equipment due to Excessive Stress Causing Pipe Failure. • Same notes as for X27. • $F(X38) = 1.1 \cdot 10^{-5}$ ruptures/(km•year) $= 9.86 \cdot 10^{-6}$ ruptures/(SE•year)
X39	Rupture of Surface Equipment due to Other Operator Error. • No recorded failures due to this causal factor over 15 year period. • Same notes as for X27. • Assumed frequency is $F(X39) = 1.06 \cdot 10^{-6}$ ruptures/(km•year) $= 9.86 \cdot 10^{-7}$ ruptures/(SE•year)
X40	Rupture of Surface Equipment due to Overpressure. • 1 recorded failure due to this causal factor over 15 year period. • $F(X40) = 2.11 \cdot 10^{-6}$ ruptures/(km•year) $= 1.97 \cdot 10^{-6}$ ruptures/(SE•year)

X41 Check Valve Unavailable due to Check Valve Failure.

- Check or Block valve will prevent reverse flow if it operates properly.
- General failure data given for check valves in Lees (1980):

$\lambda = 1.0 \cdot 10^{-4}$ failures/day

$= (1.0 \cdot 10^{-4})(365) = 3.7 \cdot 10^{-2}$ failures/year

- Fractional down time (F_{DT_e}), or the probability that the valve will not operate when demanded, assuming a two month inspection interval (τ) is given by Kletz (1986):

$$F_{DT_e} = \frac{1}{2}\lambda\tau$$

$$= \frac{1}{2}(3.7 \cdot 10^{-2})\left(\frac{2}{12}\right)$$

$$= 3.08 \cdot 10^{-3}$$

A1 Sour Gas Release from Pipeline Rupture for Given Emission Rate, Geometry and Meteorology.

$F(A1) = F(A2) \cdot P(X1) \cdot P(X2) \cdot P(A3) = 2.51 \cdot 10^{-6}$ ruptures/km•year

A2 Sour Gas Release from Pipeline Rupture.

$F(A2) = F(A4) \cdot P(X3)$

$= (7.45 \cdot 10^{-4})(1.0)$

$= 7.45 \cdot 10^{-4}$ ruptures/(km•year) which is an aggregate value.

A3 Probability of a Potential Emission Rate.

- Four possible flow Scenarios were identified in the Volume 5 report. It is assumed that each ESD valve is coupled with a check valve.
- ESD Valve unavailability (does not operate) is given by P(A5), and availability (operates) by 1-P(A5).
- Check valve unavailability is given by P(A25), and availability by 1-P(A25).
- The equations to estimate probabilities for potential emission rates and the estimated probabilities are:

Flow Scenario	Equation	P(X4)	P(A3)
End Pipe Rupture	$P(X4)[1-P(A5)]^2$	0.89 0.11	$8.7 \cdot 10^{-1}$ $1.07 \cdot 10^{-1}$
ESD Valve Rupture	$P(X4)[1-P(A5)]^2P(A25)$	0.89 0.11	$4.9 \cdot 10^{-3}$ $6.07 \cdot 10^{-4}$
Center Pipe Rupture	$P(X4)[1-P(A5)]^2$	0.89 0.11	$8.7 \cdot 10^{-1}$ $1.07 \cdot 10^{-1}$
Decay to Steady State	$P(X4)P(A5)[1-P(A5)]$	0.89 0.11	$1.02 \cdot 10^{-2}$ $1.28 \cdot 10^{-3}$

A4 Sour Gas Pipeline Rupture.

$F(A4) = F(A7) + F(A8)\, x\rho_{SET} + F(X5)$

$= 6.37 \cdot 10^{-4} + 8.12 \cdot 10^{-5}(1.07) + 2.11 \cdot 10^{-5}$

$= 7.45 \cdot 10^{-4}$ ruptures/(km•year)

A5 ESD Valve Unavailable.

$P(A5) = P(A6) + P(X6) + P(X7)$

$= 9.17 \cdot 10^{-3} + 6.75 \cdot 10^{-5} + 2.50 \cdot 10^{-3}$

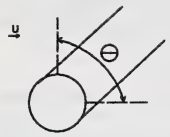
$= 1.17 \cdot 10^{-2}$

A6	ESD Valve Failure. • General failure data for pneumatic actuators obtained from Henley and Kumamoto (1981). • Failure rate given is $3.0 \cdot 10^{-4}$ failures/day, thus: $\lambda = (3.0 \cdot 10^{-4})(365) = 0.11$ failures/year • Fractional down time for ESD valves, or the probability of the valve not responding when demanded obtained from Kletz (1986): $F_{DT_V} = \frac{1}{2}\lambda\tau$ τ = time between inspections = 2 months Fountain/Havelock - (26/03/87) $= \frac{1}{2}(0.11)\left(\frac{2}{12}\right)$ $= 9.17 \cdot 10^{-3}$ • Therefore: $P(A6) = 9.17 \cdot 10^{-3}$ • Once specific data on ESD Valves is obtained, this event can be quantified by P(A6) = P(X8) + P(X9)
A7	Rupture of Buried Pipe. F(A7) = F(A9) + F(A10) + F(A11) + F(A12) $= 2.03 \cdot 10^{-4} + 1.16 \cdot 10^{-4} + 6.33 \cdot 10^{-5} + 2.55 \cdot 10^{-4}$ $= 6.37 \cdot 10^{-4}$ ruptures/(km•year)
A8	Rupture of Surface Equipment. F(A8) = F(A13) + F(A14) + F(A15) + F(A16) $= 8.87 \cdot 10^{-6} + 5.42 \cdot 10^{-6} + 6.40 \cdot 10^{-5} + 2.96 \cdot 10^{-6}$ $= 8.12 \cdot 10^{-5}$ ruptures/(SE•year)
A9	Rupture of Buried Pipe due to Corrosion. F(A9) = F(A17) + F(A20) + F(X10) + F(X11) $= 1.27 \cdot 10^{-4} + 6.33 \cdot 10^{-5} + 2.11 \cdot 10^{-6} + 1.05 \cdot 10^{-5}$ $= 2.03 \cdot 10^{-4}$ ruptures/(km•year)
A10	Rupture of Buried Pipe due to External Forces. F(A10) = F(X19) + F(X20) + F(X21) $= 1.05 \cdot 10^{-5} + 6.33 \cdot 10^{-5} + 4.22 \cdot 10^{-5}$ $= 1.16 \cdot 10^{-4}$ ruptures/(km•year)
A11	Rupture of Buried Pipe due to Operation Induced Failures. F(A11) = F(X22) + F(X23) $= 4.22 \cdot 10^{-5} + 2.11 \cdot 10^{-5}$ $= 6.33 \cdot 10^{-5}$ ruptures/(km•year)
A12	Rupture of Buried Pipe due to Equipment Failures. F(A12) = F(A22) + F(X24) $= 2.13 \cdot 10^{-4} + 9.95 \cdot 10^{-6}$ $= 2.55 \cdot 10^{-4}$ ruptures/km•year
A13	Rupture of Surface Equipment due to Corrosion. F(A13) = F(X27) + F(X28) $= 5.92 \cdot 10^{-6} + 2.96 \cdot 10^{-6}$ $= 8.87 \cdot 10^{-6}$ ruptures/SE•year

A14	Rupture of Surface Equipment due to External Forces. $F(A14) = F(X29) + F(X30) + F(X31)$ $= 1.97 \cdot 10^{-6} + 2.96 \cdot 10^{-6} + 4.93 \cdot 10^{-7}$ $= 5.42 \cdot 10^{-6}$ ruptures/SE•year
A15	Rupture of Surface Equipment due to Equipment Failures. $F(A15) = F(A23) + F(A24) + F(X32) + F(X33)$ $= 4.22 \cdot 10^{-5} + 9.95 \cdot 10^{-6} + 9.86 \cdot 10^{-6} + 1.97 \cdot 10^{-6}$ $= 6.4 \cdot 10^{-5}$ ruptures/SE•year
A16	Rupture of Surface Equipment due to Operation Induced Failures. $F(A16) = F(X39) + F(X40)$ $= 9.86 \cdot 10^{-7} + 1.97 \cdot 10^{-6}$ $= 2.96 \cdot 10^{-6}$ ruptures/(SE•year)
A17	Rupture of Buried Pipe due to Internal Corrosion. • Data does not allow further segregation of this causal factor, although further segregation is possible. • 6 ruptures were reported due to this cause. • Frequency of Occurrence is estimated as: $F(A17) = 6$ ruptures/(47400 km•year) $= 1.27 \cdot 10^{-4}$ ruptures/(km•year) • Once this event can be further developed, its frequency can be estimated by: $F(A17) = F(A18) \cdot P(X12)$
A18	Rupture of Buried Pipe due to Water in Pipe Causing Internal Corrosion. • Data on Internal Corrosion failures does not allow further segregation. • Internal corrosion frequency estimated for event A17 based on Internal Corrosion failures and km • year of sour gas pipeline service. • Once this event can be further developed, its frequency can be estimated by: $F(A18) = F(A19) \cdot P(X13)$
A19	Rupture of Buried Pipe due to Inadequate Water Removal Causing Internal Corrosion. • Same explanatory notes as for A18. • Once this event can be further developed, its frequency can be estimated by: $F(A19) = F(X14) + F(X15)$
A20	Rupture of Buried Pipe due to External Corrosion. • Data does not allow further segregation of this causal factor, although further segregation is possible. • 3 ruptures were reported due to this cause. • Frequency of Occurrence is estimated as: $F(A20) = 3$ ruptures/(47400 km•year) $= 6.33 \cdot 10^{-5}$ ruptures/(km•year) • Once this event can be further developed, its frequency can be estimated by: $F(A20) = F(A21) + P(X16)$
A21	Rupture of Buried Pipe due to Inadequate Surface Coating causing External Corrosion. • Data on External Corrosion failures does not allow further segregation. • External corrosion frequency estimated for A20 based on External Corrosion failures and km • year of sour gas pipeline service. • Once this event can be further developed, its frequency can be estimated by: $F(A21) = F(X17) + F(X18)$
A22	Rupture of Buried Pipe due to Pipe Failure. $F(A22) = F(X25) + F(X26)$ $= 2.11 \cdot 10^{-4} + 1.98 \cdot 10^{-6}$ $= 2.13 \cdot 10^{-4}$ ruptures/km•year

A23	Rupture of Surface Equipment due to Valve/Fitting Failure. • Data on Valve/Fitting failures does not allow further segregation, although further segregation is possible. • 2 ruptures were reported due to this cause. • Frequency of occurrence is estimated as: $F(A23) = 2 \text{ ruptures}/(47400 \text{ km•year})/1.07 = (4.22•10^{-5}) \text{ ruptures}/(\text{km•year})$ • Once this event can be further developed, its frequency can be estimated by: $F(A23) = F(X34) + F(X35) + F(X36)$
A24	Rupture of Surface Equipment due to Pipe Failure. $F(A24) = F(X37) + F(X38)$ $= 9.27•10^{-8} + 9.86•10^{-6}$ $= 9.95•10^{-6}$ ruptures/(SE•year)
A25	Check Valve Unavailable. $P(A25) = P(X6) + P(X7) + P(X41)$ $= 6.7•10^{-5} + 2.5•10^{-3} + 3.1•10^{-3}$ $= 5.65•10^{-3}$

D2.1 Pipeline Fault Tree - Leaks

X1	Probability of a Potential Geometry.  • Geometry defined in terms of angle normal to wind direction. • Current database does not allow detailed quantification of this probability. • For surface release horizontal jet geometry assumed since this is the worst case and P(X1) = 0.5 for both upwind jet and downwind jet. • For a subsurface release cloud geometry assumed, with P(X1) = 1.0.
X2	Probability of a Potential Meteorology. • Joint probabilities are determined in terms of the following parameters. • surface heat flux for stable and unstable atmospheres • wind speed • wind direction • atmospheric stability • mixing height for unstable atmospheres • Raw weather data gathered from the nearest Met. Station. • P(X2) = 0.0628 from processed data for base case (see Appendix E).
X3	Non - Ignition. • Quasi - immediate ignition following a pipeline rupture very rare according to historical information. • P(X3) = 1.0 (conservative).
X4	Probability of a Potential Hole Size. • 8 ruptures categorized as short ruptures and 1 rupture is long rupture (rupture definitions in Volume 5 report). • from above data, P(X4) = 0.89 for short ruptures (32%) of opening and P(X4) = 0.11 = $1.1 \cdot 10^{-1}$ for long ruptures (100% of opening). Table A.9.
X5	Miscellaneous other Leaks. • 5 such identified leaks have occurred over approximately (47400 km•year) of sour gas pipeline service (1975-1989). • F(X5) = 9/(47400 km•year) = $1.05 \cdot 10^{-4}$ leaks/(km•year) ERCB Volume 7.
X6	Third Party Damage to ESD Valves. • No known incidences of this type have occurred over the time period from which data was gathered. • Since these installations are above ground, they are not prone to accidental third party damage. • $P(X6) = \frac{1}{2}\lambda\tau = \frac{(8.1 \cdot 10^{-4})\left(\frac{2}{12}\right)}{2}$ $= 6.75 \cdot 10^{-5}$

X7	ESD Valve Unavailable due to Operator Error. • Bercha - Shell Bearberry, (Dec, 1986) gives the following rate, λ^*, for ESD Valve failure due to Operator Error: $\lambda^* = 5.0 \cdot 10^{-3}$ failures/demand • Assuming an inspection interval of 2 months (τ) (Ref: CanOxy 1 CSC 10/06/87), the failure rate, λ, expressed in terms of failures per year can be calculated by: $\lambda = \lambda^* N^*$, where N^* = # of tests per year $= (5.0 \cdot 10^{-3})(6) = 3.0 \cdot 10^{-2}$ failures/year The desired approach would be: The fractional down time (F_{DT}) for the value due to operator error, which is the probability of failure per demand is given by Kletz (1986) as: $F_{DT} = \frac{1}{2}\lambda\tau = \frac{(3.0 \cdot 10^{-2})\left(\frac{2}{12}\right)}{2}$ $= 2.5 \cdot 10^{-3}$
X8	ESD Valve Failure due to Valve Defect. • Reliable failure data for these values in sour gas service was not available. • General failure data for pneumatic actuators obtained from Henley and Kimamoto (1981). • Probability for this event taken into account for event A6.
X9	ESD Valve Failure due to Control System Failure. • Same explanatory notes as for event X8.
X10	Leak of Buried Pipe due to Inadequate Pipe Material Leading to Corrosion. • No recorded failures due to this causal factor for time period over which data was gathered (15 years). • Incident rate is non-zero and lies between 0 and 1 in 15 years. • Since quality control procedures are high for sour gas service, incident rate is expected to be low. • 0.1 leaks per 15 years is assumed as an incident rate for this event. • The frequency of occurrence is then estimated as: $F(X10) = 0.1$ leak/(47400 km•year) $= 2.11 \cdot 10^{-6}$ leaks/(km•year)
X11	Leak of Buried Pipe due to Corrosion at Girth or Fillet Weld. • 1 recorded failure due to this causal factor for time period over which data was gathered (15 years). • Welds are discontinuities along the pipeline and are likely corrosion initiation points. Incidence data does not reflect this. Lack of sufficient detail in reporting could have led to weld corrosion failures reported as internal corrosion. • 1.0 leaks per 15 years is assumed as an incident rate for this event. • The frequency of occurrences is then estimated as: $F(X11) = 1.0$ leaks/(47400 km•year) $= 2.11 \cdot 10^{-5}$ leaks/(km•year)
X12	Leak of Buried Pipeline due to No Chemical Control Leading to Internal Corrosion. • Data on Internal Corrosion failures does not allow further segregation. More detailed reporting and analysis would be required. • Internal corrosion frequency estimated for event A17 based on reported internal corrosion failures and km • year of sour pipeline service.
X13	Leak of Buried Pipeline due to Water in Gas Stream Leading to Internal Corrosion. • Same explanatory notes as for X12.
X14	Leak of Buried Pipeline due to Line Heater Failure leading to Internal Corrosion. • Same explanatory notes as for X12.

X15	Leak of Buried Pipeline due to Insufficient Gas Velocity leading to Internal Corrosion. • Same explanatory notes as for X12.
X16	Leak of Buried Pipeline due to Inadequate Cathodic Protection Leading to External Corrosion. • Data on Internal Corrosion cannot be further segregated. More detailed reporting and analysis would be required. • External corrosion frequency estimated for event A20 based on reported external corrosion failures and km • year of sour gas pipeline service.
X17	Leak of Buried Pipeline due to Surface Coating Deteriorated Leading to External Corrosion. • Same explanatory notes as for X16.
X18	Leak of Buried Pipeline due to Improper Application of Surface Coating Leading to External Corrosion. • Same explanatory notes as for X16.
X19	Leak of Buried Pipe due to Earth Movement. • No recorded failures due to this causal factor over 15 years • 2 leaks in 15 years is assumed as an incident rate for this event. • The frequency of occurrence is then estimated as: $F(X19) = 0.5/(47400 \text{ km•year}) = 4.22 \cdot 10^{-5}$ leaks/(km•year)
X20	Leak of Buried Pipe due to Third Party Damage. • 1 leak reported due to this cause. See Table A.8 • Frequency of Occurrence is estimated as: $F(X20) = 1 \text{ leak}/(47400 \text{ km•year}) = 2.11 \cdot 10^{-5}$ leaks/(km•year)
X21	Leak of Buried Pipe Due to Construction Damage. • 3 leaks reported due to this cause. See Table A.8 • Frequency of Occurrence is estimated as: $F(X21) = 3 \text{ leaks}/(47400 \text{ km•year}) = 6.33 \cdot 10^{-5}$ leaks/(km•year)
X22	Leak of Buried Pipe due to Overpressure. • 0 leak reported due to this cause. See Table A.8
X23	Leak of Buried Pipe due to Operator Error. • 0 leak reported due to this cause. See Table A.8

X24	Leak of Buried Pipe due to Weld Failure. • 18 leaks reported due to this cause. See Table A.8 • Frequency of occurrence is estimated as: F(X24) = 1 leak/(47400 km•year) = $3.8 \cdot 10^{-4}$ leaks/(km•year)
X25	Leak of Buried Pipe due to Excessive Stress causing Pipe Failure. • Analysis of reports on leaks due to pipe failures indicate all failures can be attributed to excessive stress. • 19 leaks were reported due to Pipe failure. See Table A.8 • Frequency of Occurrence is estimated as: F(X25) = 19 leaks/(47400 km•year) = $4.01 \cdot 10^{-4}$ leaks/(km•year)
X26	Leak of Buried Pipe due to Installation of Wrong Pipe Material. • Due to the current required quality control procedures, expect this frequency to be very low. • Frequency of Occurrence can be synthesized from the number of pipe installations over the 15 year period and the probability of wrong installation. • (i) Number of installations • It is assumed that each installation of new pipe has an average length of 2.7 km. • Length of new pipe installed over 15 year period is approximately 4000 km (5500-1500). • Thus 1500 installations are assumed. • (ii) Probability of Incorrect Pipe/Pipe material being installed is $6.3 \cdot 10^{-5}$. • The above probability is the product of probabilities of human error during (a) design (0.025), (b) installation (0.05), and (c) Inspection (0.05). (Sandia, 1983) • The synthesized number of failures is 0.094. • The frequency of occurrence is estimated as: F(X26) = 0.094 leaks/(47400 km•year) = $1.98 \cdot 10^{-6}$ leaks/(km•year)

X27	Leak of Surface Equipment Due to Internal Corrosion. • No recorded failures due to this causal factor over 15 year period. • Failure frequency is non-zero and is assumed to be 5% of that for Internal Corrosion of buried pipe: $F(X27) = 1.43 \cdot 10^{-4}$ leaks/(km•year) • This seems to be an adequate assumption since only approximately 1% of total sour gas pipeline length is above ground but the discontinuities due to surface equipment will increase the likelihood of corrosion. • For the sour gas pipeline network, surface equipment (SE) are classified as ESD valves, Block Valves, Check Valves, Line heaters and compressors. • Each Sour gas well (> 1.00 H_2S is assumed to have an ESD and one line heater or compressor. • Number of SE's determined as follows. Number of km of Sour Pipeline (Verified to 1986) = 5500 km Number of Sour Wells = 1936 (1) Number of Wellhead ESD's = 1936 (2) Number of Line heaters or Compressors = 1936 (3) Number of Main line ESD's = $5500 \cdot \frac{73}{688}$ = 584 (4) Number of Check Valves = $\frac{\left(\frac{5500}{688} + \frac{1936}{223}\right)}{2} \cdot 169$ = 1409 Total of 1, 2, 3 + 4 = 5865 • Number of SE's per km $\rho_{SE} = \frac{5865}{5500} = 1.07 \frac{SE's}{km}$ • Then $F(X27) = 1.43 \cdot 10^{-4}$ leaks/(km•year)• $\frac{1 \ km}{1.07 \ SE}$ $= 1.33 \cdot 10^{-4}$ leaks/(SE•year)
X28	Leak of Surface Equipment due to External Corrosion. • Same explanatory notes as for X27. • $F(X28) = 6.12 \cdot 10^{-5}$ leaks/(km•year) $= 5.72 \cdot 10^{-5}$ leaks/(SE•year)
X29	Leak of Surface Equipment due to Construction Damage. • Same explanatory notes as for X27. • $F(X29) = 3.17 \cdot 10^{-6}$ leaks/(km•year) $= 2.96 \cdot 10^{-6}$ leaks/(SE•year)
X30	Leak of Surface Equipment Due to Third Party Damage • No recorded failures for this causal factor over 15 year period. • Same explanatory notes as for X27. • $F(X30) = 1.05 \cdot 10^{-6}$ leaks/(km•year) $= 9.86 \cdot 10^{-7}$ leaks/(SE•year)
X31	Leak of Surface Equipment due to Earth Movement. • No recorded failures for this causal factor over 15 year period. • Same explanatory notes as for X27. • $F(X30) = 2.11 \cdot 10^{-6}$ leaks/(km•year) $= 1.97 \cdot 10^{-6}$ leaks/(SE•year)

X32	Leak of Surface Equipment due to Failure of an Installation. • No recorded failures for this causal factor over 15 year period. • Frequency of occurrence is non-zero. This event would account for spontaneous failures. • 1.8% of leaks were attributed to this cause. • The frequency of occurrence is then estimated as: $F(X32) = 1 \text{ leak}/(47400 \text{ km} \cdot \text{year}) = 2.1 \cdot 10^{-5} \text{ leaks}/(\text{km} \cdot \text{year})$ $= 1.97 \cdot 10^{-5} \text{ leaks}/(\text{SE} \cdot \text{year})$
X33	Leaks of Surface Equipment due to Weld Failures. • Same explanatory notes as for X27. • $F(X33) = 1.89 \cdot 10^{-5} \text{ leaks}/(\text{km} \cdot \text{year})$ $= 1.77 \cdot 10^{-5} \text{ leaks}/(\text{SE} \cdot \text{year})$
X34	Leak of Surface Equipment due to Incorrect Installation of a Valve/Fitting. • Data on Valve/Fitting failures cannot be segregated further. • Valve/Fitting failure frequency estimated for event A23, based on Valve/Fitting failures and km • year of sour pipeline service.
X35	Leak of Surface Equipment due to Inadequate Valve/Fitting Material. • Same notes as for X34.
X36	Leak of Surface Equipment due to Damaged Valve/Fitting. • Same notes as for X35.
X37	Leak of Surface Equipment due to Installation of Wrong Pipe Material. • Same notes as for X27. • $F(X37) = 9.9 \cdot 10^{-8} \text{ leaks}/(\text{km} \cdot \text{year})$ $= 9.27 \cdot 10^{-8} \text{ leaks}/(\text{SE} \cdot \text{year})$
X38	Leak of Surface Equipment due to Excessive Stress Causing Pipe Failure. • Same notes as for X27. • $F(X38) = 2.00 \cdot 10^{-5} \text{ leaks}/(\text{km} \cdot \text{year})$ $= 1.87 \cdot 10^{-5} \text{ leaks}/(\text{SE} \cdot \text{year})$
X39	Leak of Surface Equipment due to Other Operator Error. • No recorded failures due to this causal factor over 15 year period. • Same notes as for X27. • Assumed frequency is $F(X39) = 0.0 \text{ leak}/(\text{km} \cdot \text{year})$ $= 0.0 \text{ leak}/(\text{SE} \cdot \text{year})$
X40	Leak of Surface Equipment due to Overpressure. • No recorded failure due to this causal factor over 15 year period. • $F(X40) = 0.0 \text{ leak}/(\text{km} \cdot \text{year})$ $= 0.0 \text{ leak}/(\text{SE} \cdot \text{year})$

X41 Check Valve Unavailable due to Check Valve Failure.

- Check or Block valve will prevent reverse flow if it operates properly.
- General failure data given for check valves in Lees (1980):

$\lambda = 1.0 \cdot 10^{-4}$ failures/day

$= (1.0 \cdot 10^{-4})(365) = 3.7 \cdot 10^{-2}$ failures/year

- Fractional down time (F_{DT_c}), or the probability that the valve will not operate when demanded, assuming a two month inspection interval (τ) is given by Kletz (1986):

$$F_{DT_c} = \frac{1}{2}\lambda\tau$$

$$= \frac{1}{2}(3.7 \cdot 10^{-2})\left(\frac{2}{12}\right)$$

$$= 3.08 \cdot 10^{-3}$$

A1 Sour Gas Release from Pipeline Leak for Given Emission Rate, Geometry and Meteorology.

$F(A1) = F(A2) \cdot P(X1) \cdot P(X2) \cdot P(A3) = 1.48 \cdot 10^{-4}$ leaks/km•year

A2 Sour Gas Release from Pipeline Leak.

$F(A2) = F(A4) \cdot P(X3)$

$= (5.42 \cdot 10^{-3})(1.0)$

$= 5.42 \cdot 10^{-3}$ leaks/(km•year) which is an aggregate value.

A3 Probability of a Potential Emission Rate.

- Four possible flow Scenarios were identified in the Volume 5 report. It is assumed that each ESD valve is coupled with a check valve.
- ESD Valve unavailability (does not operate) is given by P(A5), and availability (operates) by 1-P(A5).
- Check valve unavailability is given by P(A25), and availability by 1-P(A25).
- The equations to estimate probabilities for potential emission rates and the estimated probabilities are:

Flow Scenario	Equation	P(X4)	P(A3)
Center Pipe Leak	$P(X4)[1-P(A5)]^2$	0.89	$8.7 \cdot 10^{-1}$

A4 Sour Gas Pipeline Leak.

$F(A4) = F(A7) + F(A8)\, x\rho_{SET} + F(X5)$

$= 5.00 \cdot 10^{-3} + 2.95 \cdot 10^{-4}(1.07) + 1.05 \cdot 10^{-4}$

$= 5.42 \cdot 10^{-3}$ leaks/(km•year)

A5 ESD Valve Unavailable.

$P(A5) = P(A6) + P(X6) + P(X7)$

$= 9.17 \cdot 10^{-3} + 6.75 \cdot 10^{-5} + 2.50 \cdot 10^{-3}$

$= 1.17 \cdot 10^{-2}$

A6	ESD Valve Failure. • General failure data for pneumatic actuators obtained from Henley and Kumamoto (1981). • Failure rate given is $3.0 \cdot 10^{-4}$ failures/day, thus: $\lambda = (3.0 \cdot 10^{-4})(365) = 0.11$ failures/year • Fractional down time for ESD valves, or the probability of the valve not responding when demanded obtained from Kletz (1986): $$F_{DT_V} = \frac{1}{2}\lambda\tau$$ τ = time between inspections = 2 months Fountain/Havelock - (26/03/87) $= \frac{1}{2}(0.11)\left(\frac{2}{12}\right)$ $= 9.17 \cdot 10^{-3}$ • Therefore: $P(A6) = 9.17 \cdot 10^{-3}$ • Once specific data on ESD Valves is obtained, this event can be quantified by P(A6) = P(X8) + P(X9)
A7	Leak of Buried Pipe. F(A7) = F(A9) + F(A10) + F(A11) + F(A12) $= 4.09 \cdot 10^{-3} + 1.27 \cdot 10^{-4} + 0.0 + 7.83 \cdot 10^{-4}$ $= 5.00 \cdot 10^{-3}$ leaks/(km•year)
A8	Leak of Surface Equipment. F(A8) = F(A13) + F(A14) + F(A15) + F(A16) $= 1.90 \cdot 10^{-4} + 5.92 \cdot 10^{-6} + 9.85 \cdot 10^{-5} + 0.0$ $= 2.95 \cdot 10^{-4}$ leaks/(SE•year)
A9	Leak of Buried Pipe due to Corrosion. F(A9) = F(A17) + F(A20) + F(X10) + F(X11) $= 0.0 + 2.11 \cdot 10^{-6} + 2.11 \cdot 10^{-5} + 1.22 \cdot 10^{-3}$ $= 4.09 \cdot 10^{-3}$ leaks/(km•year)
A10	Leak of Buried Pipe due to External Forces. F(A10) = F(X19) + F(X20) + F(X21) $= 4.22 \cdot 10^{-5} + 2.11 \cdot 10^{-5} + 6.33 \cdot 10^{-5}$ $= 1.27 \cdot 10^{-4}$ leaks/(km•year)
A11	Leak of Buried Pipe due to Operation Induced Failures. F(A11) = F(X22) + F(X23) = 0 + 0 = 0 leak/(km•year)
A12	Leak of Buried Pipe due to Equipment Failures. F(A12) = F(A22) + F(X24) $= 1.92 \cdot 10^{-4} + 1.35 \cdot 10^{-5}$ $= 7.83 \cdot 10^{-4}$ leaks/km•year
A13	Leak of Surface Equipment due to Corrosion. F(A13) = F(X27) + F(X28) $= 1.33 \cdot 10^{-4} + 5.72 \cdot 10^{-5}$ $= 1.90 \cdot 10^{-4}$ leaks/SE•year

A14	Leak of Surface Equipment due to External Forces. $F(A14) = F(X29) + F(X30) + F(X31)$ $= 2.96 \cdot 10^{-6} + 9.86 \cdot 10^{-7} + 1.97 \cdot 10^{-6}$ $= 5.92 \cdot 10^{-6}$ leaks/SE•year
A15	Leak of Surface Equipment due to Equipment Failures. $F(A15) = F(A23) + F(A24) + F(X32) + F(X33)$ $= 4.22 \cdot 10^{-5} + 1.88 \cdot 10^{-5} + 1.97 \cdot 10^{-5} + 1.77 \cdot 10^{-5}$ $= 9.85 \cdot 10^{-5}$ leaks/SE•year
A16	Leak of Surface Equipment due to Operation Induced Failures. $F(A16) = F(X39) + F(X40)$ $= 2.96 \cdot 10^{-5} + 2.96 \cdot 10^{-6} + 0.0 + 0.0$ = 0 leak/(SE•year)
A17	Leak of Buried Pipe due to Internal Corrosion. • Data does not allow further segregation of this causal factor, although further segregation is possible. • 5 leaks were reported due to this cause. • Frequency of Occurrence is estimated as: $F(A17) = 5$ leaks/(47400 km•year) $= 2.85 \cdot 10^{-3}$ leaks/(km•year) • Once this event can be further developed, its frequency can be estimated by: $F(A17) = F(A18) \cdot P(X12)$
A18	Leak of Buried Pipe due to Water in Pipe Causing Internal Corrosion. • Data on Internal Corrosion failures does not allow further segregation. • Internal corrosion frequency estimated for event A17 based on Internal Corrosion failures and km • year of sour gas pipeline service. • Once this event can be further developed, its frequency can be estimated by: $F(A18) = F(A19) \cdot P(X13)$
A19	Leak of Buried Pipe due to Inadequate Water Removal Causing Internal Corrosion. • Same explanatory notes as for A18. • Once this event can be further developed, its frequency can be estimated by: $F(A19) = F(X14) + F(X15)$
A20	Leak of Buried Pipe due to External Corrosion. • Data does not allow further segregation of this causal factor, although further segregation is possible. • 2.9 leaks were reported due to this cause. • Frequency of Occurrence is estimated as: $F(A20) = 2.9$ leaks/(47400 km•year) $= 1.22 \cdot 10^{-3}$ leaks/(km•year) • Once this event can be further developed, its frequency can be estimated by: $F(A20) = F(A21) + P(X16)$
A21	Leak of Buried Pipe due to Inadequate Surface Coating causing External Corrosion. • Data on External Corrosion failures does not allow further segregation. • External corrosion frequency estimated for A20 based on External Corrosion failures and km • year of sour gas pipeline service. • Once this event can be further developed, its frequency can be estimated by: $F(A21) = F(X17) + F(X18)$
A22	Leak of Buried Pipe due to Pipe Failure. $F(A22) = F(X25) + F(X26)$ $= 4.01 \cdot 10^{-4} + 1.98 \cdot 10^{-6}$ $= 4.03 \cdot 10^{-4}$ leaks/km•year

A23	Leak of Surface Equipment due to Valve/Fitting Failure. • Data on Valve/Fitting failures does not allow further segregation, although further segregation is possible. • 2 leaks were reported due to this cause. • Frequency of occurrence is estimated as: $F(A23) = 2 \text{ leaks}/(47400 \text{ km•year})/1.07 = (4.22•10^{-5}) \text{ leaks}/(\text{km•year})$ • Once this event can be further developed, its frequency can be estimated by: $F(A23) = F(X34) + F(X35) + F(X36)$
A24	Leak of Surface Equipment due to Pipe Failure. $F(A24) = F(X37) + F(X38)$ $= 9.27•10^{-8} + 1.87•10^{-5}$ $= 1.88•10^{-5} \text{ leaks}/(\text{SE•year})$
A25	Check Valve Unavailable. $P(A25) = P(X6) + P(X7) + P(X41)$ $= 6.75•10^{-5} + 2.50•10^{-3} + 3.08•10^{-3}$ $= 5.65•10^{-3}$

APPENDIX E

PROBABILITY OF METEOROLOGICAL CONDITIONS

• Description of Base Case Meteorological Conditions

Wind Direction:	$0 < \theta \leq 180^{o}$ clockwise from North (Easterly)
Wind Speed:	$0 \leq U_{REF} \leq 1.0 m/s$ (1 m/s used as representative)
Atmospheric Stability:	Stable
Surface Heat flux:	$-27 \leq H_O < -5 W/m^2$ (-15 W/m^2 used as representative)

• The following was observed for 5 years of processed meteorological data from Calgary International Airport (1980-84).

Stable,	< 1 m/s winds
East Winds	74 cases
West Winds	123 cases
Calms	2555 cases

• Total cases (hours) = 43824

• Joint frequency of Base Case ($P_{M,J}$) (all directions)

$$P_{M,J} = \frac{74 + 123 + 2555}{43824} = 0.0628$$

• "East" calms estimated by 74/(74+123) (2555) = 960

• Joint frequency of "East" winds (including calms) with Stable low winds

$$P_{M,J} = \frac{74 + 960}{43824} = 0.0236$$

Table E.1

Distribution of Estimated Stability Classes During Reported Non-Calm and Calm Periods.

Calgary International Airport
(1980 to 1984)

Stability	Calm (%)	Non-Calm (%)	Total (%)
Unstable	823 (22.6)	8931 (22.2)	9754 (22.3)
Neutral	261 (7.2)	15549 (38.7)	15810 (36.1)
Stable	2555 (70.2)	15704 (39.1)	18259 (41.6)
Total	3639 (100.0)	40184 (100.0)	43823 * (100.0)

- Total number of hours for the 5 year period = 43824. Difference due to one bad data point.

Table E.2

Distribution of Wind Speed During Estimated Unstable Conditions.

Calgary International Airport
(1980 to 1984)

Wind Speed Class (m/s)	Number	Percent of Unstable (%)	Percent of Total (%)
<1.0	953	9.8	2.2
1.01 to 2.0	2324	23.8	5.3
2.01 to 3.0	718	7.4	1.6
3.01 to 4.0	1636	16.8	3.7
4.01 to 5.0	1494	15.3	3.4
5.01 to 6.0	1076	11.0	2.5
6.01 to 7.0	826	8.5	1.9
7.01 to 8.0	419	4.3	1.0
8.01 to 9.0	163	1.7	0.4
9.01 to 10.0	91	0.9	0.2
10.01 to 11.0	32	0.3	0.1
11.01 to 12.0	15	0.2	0.0
12.01 to 13.0	3	0.0	0.0
13.01 to 14.0	2	0.0	0.0
>14.0	2	0.0	0.0
Total	9754	100.0	22.3

- Total number of usable hours for the 5 year period = 43823.

Table E.3

Distribution of Wind Speed During Estimated Neutral Conditions.

Calgary International Airport
(1980 to 1984)

Wind Speed Class (m/s)	Number	Percent of Neutral (%)	Percent of Total (%)
<1.0	288	1.8	0.7
1.01 to 2.0	931	5.9	2.1
2.01 to 3.0	538	3.4	1.2
3.01 to 4.0	1321	8.4	3.0
4.01 to 5.0	1454	9.2	3.3
5.01 to 6.0	2075	13.1	4.7
6.01 to 7.0	1925	12.2	4.4
7.01 to 8.0	2488	15.7	5.7
8.01 to 9.0	1676	10.6	3.8
9.01 to 10.0	1210	7.7	2.8
10.01 to 11.0	921	5.9	2.1
11.01 to 12.0	442	2.8	1.0
12.01 to 13.0	237	1.5	0.5
13.01 to 14.0	115	0.7	0.3
14.01 to 15.0	70	0.4	0.2
>15.0	119	0.8	0.3
Total	15810	100.0	36.1

- Total number of usable hours for the 5 year period = 43823.

Table E.4

Distribution of Wind Speed During Estimated Stable Conditions.

Calgary International Airport
(1980 to 1984)

Wind Speed Class (m/s)	Number	Percent of Stable (%)	Percent of Total (%)
<1.0	2752	15.1	6.3
1.01 to 2.0	5201	28.5	11.9
2.01 to 3.0	1886	10.3	4.3
3.01 to 4.0	3449	18.9	7.9
4.01 to 5.0	2557	14.0	5.8
5.01 to 6.0	1400	7.7	3.2
6.01 to 7.0	811	4.4	1.9
7.01 to 8.0	203	1.1	0.5
Total	18259	100.0	41.6

- Total number of usable hours for the 5 year period = 43823.

APPENDIX F

FREQUENCY ANALYSIS SENSITIVITY TABLES

TABLE F.1

DRILLING FAULT TREE EVENT SENSITIVITY ANALYSIS (BASE CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A1	USGR given E,G and M	F4		$2.53 \cdot 10^{-9}$			$1.16 \cdot 10^{-7}$			$5.20 \cdot 10^{-10}$
X1	Emission Rate	P	$3.68 \cdot 10^{-1}$		0	$3.68 \cdot 10^{-1}$		0	$3.68 \cdot 10^{-1}$	
X2	Geometry	P	$2.30 \cdot 10^{-2}$		0	$2.30 \cdot 10^{-2}$		0	$2.30 \cdot 10^{-2}$	
X3	Meteorology	P	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$	
*	USGR	F4		$4.76 \cdot 10^{-6}$			$2.17 \cdot 10^{-4}$			$9.79 \cdot 10^{-7}$
A46	Non-Ignition	P		$1.05 \cdot 10^{-2}$			$1.71 \cdot 10^{-1}$			$5.13 \cdot 10^{-3}$
A47	Ignition Failure	P		$5.00 \cdot 10^{-4}$			$6.05 \cdot 10^{-2}$			$1.25 \cdot 10^{-4}$
X43	Primary Ignition Failure	P	$1.00 \cdot 10^{-2}$		1000	$1.10 \cdot 10^{-1}$		-50	$5.00 \cdot 10^{-3}$	
X44	Secondary Ignition Failure	P	$5.00 \cdot 10^{-2}$		1000	$5.50 \cdot 10^{-1}$		-50	$2.50 \cdot 10^{-2}$	
X45	Operator Error	P	$1.00 \cdot 10^{-2}$		1000	$1.10 \cdot 10^{-1}$		-50	$5.00 \cdot 10^{-3}$	
A2	Uncontrolled Well Blowout	F3		$4.53 \cdot 10^{-4}$			$1.27 \cdot 10^{-3}$			$1.91 \cdot 10^{-4}$
X4	Failure to Control Blow	P	$5.56 \cdot 10^{-2}$		50	$8.34 \cdot 10^{-2}$		-25	$4.17 \cdot 10^{-2}$	
A3	Blow Occurs	F2		$1.07 \cdot 10^{-3}$			$2.01 \cdot 10^{-3}$			$6.04 \cdot 10^{-4}$
A5	Failure to Control Kick	P	$3.08 \cdot 10^{-2}$		50	$4.63 \cdot 10^{-2}$		-25	$2.31 \cdot 10^{-2}$	
A4	Kick Occurs	F1		$3.48 \cdot 10^{-2}$			$4.35 \cdot 10^{-2}$			$2.61 \cdot 10^{-2}$
A18	Kick while Drilling	F1	$1.48 \cdot 10^{-2}$		25	$1.85 \cdot 10^{-2}$		-25	$1.11 \cdot 10^{-2}$	
A19	Kick while Tripping Out	F1	$1.19 \cdot 10^{-2}$		25	$1.49 \cdot 10^{-2}$		-25	$8.95 \cdot 10^{-3}$	
A20	Kick while Tripping In	F1	$3.71 \cdot 10^{-3}$		25	$4.64 \cdot 10^{-3}$		-25	$2.78 \cdot 10^{-3}$	
A21	Kick while Circulating	F1	$9.79 \cdot 10^{-4}$		25	$1.22 \cdot 10^{-3}$		-25	$7.34 \cdot 10^{-4}$	
X31	Kick while Testing	F1	$1.06 \cdot 10^{-3}$		25	$1.33 \cdot 10^{-3}$		-25	$7.47 \cdot 10^{-4}$	
X32	Kick while Coring	F1	$1.31 \cdot 10^{-3}$		25	$1.64 \cdot 10^{-3}$		-25	$9.85 \cdot 10^{-4}$	
X33	Kick while Running Casing	F1	$6.92 \cdot 10^{-4}$		25	$8.65 \cdot 10^{-4}$		-25	$5.19 \cdot 10^{-4}$	
X34	Kick while Logging	F1	$2.15 \cdot 10^{-4}$		25	$2.69 \cdot 10^{-4}$		-25	$1.61 \cdot 10^{-4}$	
X34.5	Kick, Other	F1	$1.31 \cdot 10^{-4}$		25	$1.64 \cdot 10^{-4}$		-25	$9.85 \cdot 10^{-5}$	

Note:

F1 = Frequency (Kicks/Well-Drilled)
F2 = Frequency (Blows/Well-Drilled)
F3 = Frequency (Blowouts/Well-Drilled)
F4 = Frequency (USGR/Well-Drilled)
P = Probability
* = Combine (multiply) Events A2 and A46 (Not Shown on Fault Tree)
USGR = Uncontrolled Sour Gas (H_2S) Release

TABLE F.2(a)

NON-DRILLING FAULT TREE EVENT SENSITIVITY ANALYSIS (BASE CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A1	USGR for given E,G and M	F		$1.32 \cdot 10^{-7}$			$2.01 \cdot 10^{-6}$			$5.21 \cdot 10^{-8}$
X1	Potential Emission Rate	P	$4.87 \cdot 10^{-1}$		0	$4.87 \cdot 10^{-1}$		0	$4.87 \cdot 10^{-1}$	
X2	Potential Geometry	P	$2.50 \cdot 10^{-1}$		0	$2.50 \cdot 10^{-1}$		0	$2.50 \cdot 10^{-1}$	
X3	Potential Meteorology	P	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$	
A2	USGR	F		$1.73 \cdot 10^{-5}$			$2.63 \cdot 10^{-4}$			$6.82 \cdot 10^{-6}$
A3	USGR - Normal Production	F		$3.55 \cdot 10^{-6}$			$3.60 \cdot 10^{-5}$			$1.57 \cdot 10^{-6}$
X4	Non-Ignition during NP	P	$1.00 \cdot 10^{+0}$		0	$1.00 \cdot 10^{+0}$		0	$1.00 \cdot 10^{+0}$	
A6	Release from Well	F		$1.36 \cdot 10^{-4}$			$2.72 \cdot 10^{-4}$			$6.81 \cdot 10^{-5}$
A10	Operations at Well	F		$1.24 \cdot 10^{-4}$			$2.49 \cdot 10^{-4}$			$6.21 \cdot 10^{-5}$
X5	Corrosion	F	$3.80 \cdot 10^{-5}$		100	$7.61 \cdot 10^{-5}$		-50	$1.9 \cdot 10^{-5}$	
X6	Equipment Failure	F	$1.52 \cdot 10^{-5}$		100	$3.04 \cdot 10^{-5}$		-50	$7.60 \cdot 10^{-6}$	
A13	Human Error	F		$7.10 \cdot 10^{-5}$			$1.42 \cdot 10^{-4}$			$3.55 \cdot 10^{-5}$
X7	Incorrect Procedures	F	$6.42 \cdot 10^{-5}$		100	$1.28 \cdot 10^{-4}$		-50	$3.21 \cdot 10^{-5}$	
X8	Incorrect Maintenance	F	$6.76 \cdot 10^{-6}$		100	$1.35 \cdot 10^{-5}$		-50	$3.38 \cdot 10^{-6}$	
A11	External Accident	F		$1.19 \cdot 10^{-5}$			$2.38 \cdot 10^{-5}$			$5.95 \cdot 10^{-6}$
X9	Third Party Damage	F	$8.88 \cdot 10^{-6}$		100	$1.78 \cdot 10^{-5}$		-50	$4.44 \cdot 10^{-6}$	
X10	Environmental Accident	F	$3.03 \cdot 10^{-6}$		100	$6.06 \cdot 10^{-6}$		-50	$1.52 \cdot 10^{-6}$	
A7	Failure to Control Release	P		$2.61 \cdot 10^{-2}$			$1.32 \cdot 10^{-1}$			$2.31 \cdot 10^{-2}$
X11	Operator Error	P	$1.00 \cdot 10^{-2}$		500	$6.00 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-2}$	
A12	SSSV Unavailable	P		$1.61 \cdot 10^{-2}$			$7.22 \cdot 10^{-2}$			$1.31 \cdot 10^{-2}$
X12	SSSV Failure	P	$3.50 \cdot 10^{-3}$		100	$7.00 \cdot 10^{-3}$		-50	$1.75 \cdot 10^{-3}$	
X13	Incorrect SSSV Setting	P	$1.00 \cdot 10^{-2}$		500	$6.00 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-2}$	
X14	SSSV Control System Failure	P	$2.60 \cdot 10^{-3}$		100	$5.20 \cdot 10^{-3}$		-50	$1.30 \cdot 10^{-3}$	
A4	USGR - Servicing	F		$1.37 \cdot 10^{-5}$			$2.27 \cdot 10^{-4}$			$5.25 \cdot 10^{-6}$
A14	Non-Ignition during Ser.	P		$5.10 \cdot 10^{-2}$			$5.61 \cdot 10^{-1}$			$2.60 \cdot 10^{-2}$
X23	Igniter Failure	P	$5.00 \cdot 10^{-2}$		1000	$5.50 \cdot 10^{-1}$		-50	$2.50 \cdot 10^{-2}$	
X24	Operator Error	P	$1.00 \cdot 10^{-3}$		1000	$1.10 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-3}$	
A5	Release during Servicing	F	$2.69 \cdot 10^{-4}$		50	$4.04 \cdot 10^{-4}$		-25	$2.02 \cdot 10^{-4}$	

Note: F = Frequency (#/well•year)
P = Probability
USGR = Uncontrolled Sour Gas Release
SSSV = Subsurface Safety Valve

TABLE F.2(b)

NON-DRILLING NON-PRODUCING FAULT TREE EVENT SENSITIVITY ANALYSIS (BASE CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A1	USGR for given E,G and M	F		$2.20 \cdot 10^{-8}$			$2.23 \cdot 10^{-7}$			$9.70 \cdot 10^{-9}$
X1	Potential Emission Rate	P	$3.40 \cdot 10^{-1}$		0	$3.40 \cdot 10^{-1}$		0	$3.40 \cdot 10^{-1}$	
X2	Potential Geometry	P	$2.50 \cdot 10^{-1}$		0	$2.50 \cdot 10^{-1}$		0	$2.50 \cdot 10^{-1}$	
X3	Potential Meteorology	P	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$		0	$6.28 \cdot 10^{-2}$	
A2	USGR	F		$4.12 \cdot 10^{-6}$			$4.17 \cdot 10^{-5}$			$1.82 \cdot 10^{-6}$
A3	USGR - Normal Production	F		$4.12 \cdot 10^{-6}$			$4.17 \cdot 10^{-5}$			$1.82 \cdot 10^{-6}$
X4	Non-Ignition during NP	P	$1.00 \cdot 10^{+0}$		0	$1.00 \cdot 10^{+0}$		0	$1.00 \cdot 10^{+0}$	
A6	Release from Well	F		$1.58 \cdot 10^{-4}$			$3.15 \cdot 10^{-4}$			$7.89 \cdot 10^{-5}$
A10	Operations at Well	F		$1.32 \cdot 10^{-4}$			$2.64 \cdot 10^{-4}$			$6.60 \cdot 10^{-5}$
X5	Corrosion	F	$7.86 \cdot 10^{-5}$		100	$1.57 \cdot 10^{-4}$		-50	$3.93 \cdot 10^{-5}$	
X6	Equipment Failure	F	$3.14 \cdot 10^{-5}$		100	$6.28 \cdot 10^{-5}$		-50	$1.57 \cdot 10^{-5}$	
A13	Human Error	F		$2.20 \cdot 10^{-5}$			$4.40 \cdot 10^{-5}$			$1.10 \cdot 10^{-5}$
X7	Incorrect Procedures	F	$1.99 \cdot 10^{-5}$		100	$3.98 \cdot 10^{-5}$		-50	$9.95 \cdot 10^{-6}$	
X8	Incorrect Maintenance	F	$2.09 \cdot 10^{-6}$		100	$4.19 \cdot 10^{-6}$		-50	$1.05 \cdot 10^{-6}$	
A11	External Accident	F		$2.58 \cdot 10^{-5}$			$5.15 \cdot 10^{-5}$			$1.29 \cdot 10^{-5}$
X9	Third Party Damage	F	$2.20 \cdot 10^{-5}$		100	$4.40 \cdot 10^{-5}$		-50	$1.10 \cdot 10^{-5}$	
X10	Environmental Accident	F	$3.76 \cdot 10^{-6}$		100	$7.51 \cdot 10^{-6}$		-50	$1.88 \cdot 10^{-6}$	
A7	Failure to Control Release	P		$2.61 \cdot 10^{-2}$			$1.32 \cdot 10^{-1}$			$2.31 \cdot 10^{-2}$
X11	Operator Error	P	$1.00 \cdot 10^{-2}$		500	$6.00 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-2}$	
A12	SSSV Unavailable	P		$1.61 \cdot 10^{-2}$			$7.22 \cdot 10^{-2}$			$1.31 \cdot 10^{-2}$
X12	SSSV Failure	P	$3.50 \cdot 10^{-3}$		100	$7.00 \cdot 10^{-3}$		-50	$1.75 \cdot 10^{-3}$	
X13	Incorrect SSSV Setting	P	$1.00 \cdot 10^{-2}$		500	$6.00 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-2}$	
X14	SSSV Control System Failure	P	$2.60 \cdot 10^{-3}$		100	$5.20 \cdot 10^{-3}$		-50	$1.30 \cdot 10^{-3}$	
A4	USGR - Servicing	F		0			0			0
A14	Non-Ignition during Ser.	P		$5.10 \cdot 10^{-2}$			$5.61 \cdot 10^{-1}$			$2.60 \cdot 10^{-2}$
X23	Igniter Failure	P	$5.00 \cdot 10^{-2}$		1000	$5.50 \cdot 10^{-1}$		-50	$2.50 \cdot 10^{-2}$	
X24	Operator Error	P	$1.00 \cdot 10^{-3}$		1000	$1.10 \cdot 10^{-2}$		0	$1.00 \cdot 10^{-3}$	
A5	Release during Servicing	F	0		50	0		0	0	

Note: F = Frequency (#/well•year)
P = Probability
USGR = Uncontrolled Sour Gas Release
SSSV = Subsurface Safety Valve

TABLE F.3a

PIPELINE FAULT TREE EVENT SENSITIVITY ANALYSIS (BASE RUPTURE CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A1	USGR for given E, G and M	F1		NC			NC			NC
X1	Potential Geometry	P	0.5			0.5			0.5	
X2	Potential Meteorology	P	NC			NC			NC	
A3	Potential Emission Rate	P		NC			NC			NC
X4	Potential Hole Size	P	$1.10 \cdot 10^{-1}$			$1.10 \cdot 10^{-1}$			$1.10 \cdot 10^{-1}$	
A5	ESD Valve Unavailable	P		$1.17 \cdot 10^{-2}$			$2.35 \cdot 10^{-2}$			$5.87 \cdot 10^{-3}$
X6	Third Party Damage	P	$6.70 \cdot 10^{-5}$		100	$1.35 \cdot 10^{-4}$		-50	$3.38 \cdot 10^{-5}$	
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		100	$5.00 \cdot 10^{-3}$		-50	$1.25 \cdot 10^{-3}$	
A6	ESD Valve Failure	P	$9.17 \cdot 10^{-3}$		100	$1.83 \cdot 10^{-2}$		-50	$4.58 \cdot 10^{-3}$	
A25	Check Valve Unavailable	P		$5.65 \cdot 10^{-3}$			$1.13 \cdot 10^{-2}$			$4.37 \cdot 10^{-3}$
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		100	$1.35 \cdot 10^{-4}$		-50	$3.38 \cdot 10^{-5}$	
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		100	$5.00 \cdot 10^{-3}$		-50	$1.25 \cdot 10^{-3}$	
X41	Check Valve Failure	P	$3.08 \cdot 10^{-3}$		100	$6.17 \cdot 10^{-3}$		-50	$3.08 \cdot 10^{-3}$	
A2	USGR	F1		$7.45 \cdot 10^{-4}$			$1.72 \cdot 10^{-3}$			$3.23 \cdot 10^{-4}$
X3	Non-Ignition	P	1.00		0	1.00		0	1.00	
A4	SG Pipeline Rupture	F1		$7.45 \cdot 10^{-4}$			$1.72 \cdot 10^{-3}$			$3.23 \cdot 10^{-4}$
X5	Misc./Other Ruptures	F1	$2.11 \cdot 10^{-5}$		100	$4.22 \cdot 10^{-5}$		-100	0	
A7	Rupture of Buried Pipe	F1		$6.37 \cdot 10^{-4}$			$1.33 \cdot 10^{-3}$			$3.01 \cdot 10^{-4}$
A9	Corrosion	F1		$2.03 \cdot 10^{-4}$			$4.56 \cdot 10^{-4}$			$9.49 \cdot 10^{-5}$
A17	Internal Corrosion	F1	$1.27 \cdot 10^{-4}$		100	$2.53 \cdot 10^{-4}$		-50	$6.33 \cdot 10^{-5}$	
A20	External Corrosion	F1	$6.33 \cdot 10^{-5}$		100	$1.27 \cdot 10^{-4}$		-50	$3.16 \cdot 10^{-5}$	
X10	Inadequate Pipe Material	F1	$2.11 \cdot 10^{-6}$		500	$1.27 \cdot 10^{-5}$		-100	0	
X11	Corr. at Girth/Fillet Weld	F1	$1.05 \cdot 10^{-5}$		500	$6.33 \cdot 10^{-5}$		-100	0	
A10	External forces	F1		$1.16 \cdot 10^{-4}$			$2.32 \cdot 10^{-4}$			$5.80 \cdot 10^{-5}$
X19	Earth Movement	F1	$1.05 \cdot 10^{-5}$		100	$2.11 \cdot 10^{-5}$		-50	$5.27 \cdot 10^{-6}$	
X20	Third Party Damage	F1	$6.33 \cdot 10^{-5}$		100	$1.27 \cdot 10^{-4}$		-50	$3.16 \cdot 10^{-5}$	
X21	Construction Damage	F1	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-5}$		-50	$2.11 \cdot 10^{-5}$	

TABLE F.3b

PIPELINE FAULT TREE EVENT SENSITIVITY ANALYSIS (BASE RUPTURE CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A11	Operation Induced Failures	F1		$6.33 \cdot 10^{-4}$			$1.27 \cdot 10^{-4}$			$2.11 \cdot 10^{-5}$
X22	Overpressure	F1	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-5}$		-50	$2.11 \cdot 10^{-5}$	
X23	Operator Error	F1	$2.11 \cdot 10^{-5}$		100	$4.22 \cdot 10^{-5}$		-100	0	
A12	Equipment Failures	F1		$2.55 \cdot 10^{-4}$			$5.18 \cdot 10^{-4}$			$1.27 \cdot 10^{-4}$
X24	Weld Failure	F1	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-4}$		-50	$2.11 \cdot 10^{-5}$	
A22	Pipe Failure	F1		$2.13 \cdot 10^{-4}$			$4.34 \cdot 10^{-4}$			$1.05 \cdot 10^{-4}$
X25	Excessive Stresses	F1	$2.11 \cdot 10^{-4}$		100	$4.22 \cdot 10^{-4}$		-50	$1.05 \cdot 10^{-4}$	
X26	Wrong Material	F1	$1.98 \cdot 10^{-6}$		500	$1.19 \cdot 10^{-5}$		-100	0	
A8	Rupture of Surface Equip.	F2		$8.12 \cdot 10^{-5}$			$3.19 \cdot 10^{-4}$			$2.11 \cdot 10^{-5}$
A13	Corrosion	F2		$8.87 \cdot 10^{-6}$			$5.32 \cdot 10^{-4}$			0
X27	Internal Corrosion	F2	$5.92 \cdot 10^{-6}$		500	$3.55 \cdot 10^{-5}$		-100	0	
X28	External Corrosion	F2	$2.96 \cdot 10^{-6}$		500	$1.77 \cdot 10^{-5}$		-100	0	
A14	External forces	F2		$5.42 \cdot 10^{-6}$			$3.25 \cdot 10^{-4}$			0
X29	Construction Damage	F2	$1.97 \cdot 10^{-6}$		500	$1.18 \cdot 10^{-5}$		-100	0	
X30	Third Party Damage	F2	$2.96 \cdot 10^{-6}$		500	$1.77 \cdot 10^{-5}$		-100	0	
X31	Earth Movement	F2	$4.93 \cdot 10^{-7}$		500	$2.96 \cdot 10^{-6}$		-100	0	
A15	Equipment Failure	F2		$6.40 \cdot 10^{-5}$			$2.15 \cdot 10^{-4}$			$2.11 \cdot 10^{-5}$
X32	Failure of an Installation	F2	$9.86 \cdot 10^{-6}$		500	$5.92 \cdot 10^{-5}$		-100	0	
X33	Weld failure	F2	$1.97 \cdot 10^{-6}$		500	$1.18 \cdot 10^{-5}$		-100	0	
A23	Valve/Fitting Failure	F2	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-5}$		-50	$2.11 \cdot 10^{-5}$	
A24	Pipe Failure	F2		$9.95 \cdot 10^{-6}$			$5.97 \cdot 10^{-5}$			0
X37	Wrong Material	F2	$9.27 \cdot 10^{-8}$		500	$5.56 \cdot 10^{-7}$		-100	0	
X38	Excessive Stresses	F2	$9.86 \cdot 10^{-6}$		500	$5.92 \cdot 10^{-5}$		-100	0	
A16	Operation Induced Failures	F2		$2.96 \cdot 10^{-6}$			$1.77 \cdot 10^{-5}$			0
X39	Operator Error	F2	$9.86 \cdot 10^{-7}$		500	$5.92 \cdot 10^{-6}$		-100	0	
X40	Overpressure	F2	$1.97 \cdot 10^{-6}$		500	$1.18 \cdot 10^{-5}$		-100	0	

Notes: (1) F1 = Frequency (#/km•year)
F2 = Frequency (#/SE•year)
P = Probability
(2)To quantify event A4, event A8 must be multiplied by 1.07 SE's/km
(3)SE = Surface Equipment USGR = Uncontrolled sour gas (H_2S) release ESD Valve = Emergency Shutdown Valve
(4)Event A3 is computed for Flow Scenario 1 - see Appendix D
(5)NC = Not Computed
(6)Hole Size = Long Rupture, Geometry = Downwind Jet

TABLE F.3c

PIPELINE FAULT TREE EVENT SENSITIVITY ANALYSIS (LEAK CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A1	USGR for given E, G and M	F1		NC			NC			NC
X1	Potential Geometry	P	0.5			0.5			0.5	
X2	Potential Meteorology	P	NC			NC			NC	
A3	Potential Emission Rate	P		NC			NC			NC
X4	Potential Hole Size	P	$8.90 \cdot 10^{-1}$			$8.90 \cdot 10^{-1}$			$8.90 \cdot 10^{-1}$	
A5	ESD Valve Unavailable	P		$1.17 \cdot 10^{-2}$			$2.35 \cdot 10^{-2}$			$5.87 \cdot 10^{-3}$
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		100	$1.35 \cdot 10^{-4}$		-50	$3.38 \cdot 10^{-5}$	
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		100	$5.00 \cdot 10^{-3}$		-50	$1.25 \cdot 10^{-3}$	
A6	ESD Valve Failure	P	$9.17 \cdot 10^{-3}$		100	$1.83 \cdot 10^{-2}$		-50	$4.58 \cdot 10^{-3}$	
A25	Check Valve Unavailable	P		$5.65 \cdot 10^{-3}$			$1.13 \cdot 10^{-2}$			$4.37 \cdot 10^{-3}$
X6	Third Party Damage	P	$6.75 \cdot 10^{-5}$		100	$1.35 \cdot 10^{-4}$		-50	$3.38 \cdot 10^{-5}$	
X7	Operator Error	P	$2.50 \cdot 10^{-3}$		100	$5.00 \cdot 10^{-3}$		-50	$1.25 \cdot 10^{-3}$	
X41	Check Valve Failure	P	$3.08 \cdot 10^{-3}$		100	$6.17 \cdot 10^{-3}$		-50	$3.08 \cdot 10^{-3}$	
A2	USGR	F1		$5.42 \cdot 10^{-3}$			$1.20 \cdot 10^{-2}$			$2.51 \cdot 10^{-3}$
X3	Non-Ignition	P	1.00		0	1.00		0	1.00	
A4	SG Pipeline Rupture	F1		$5.42 \cdot 10^{-3}$			$1.20 \cdot 10^{-2}$			$2.51 \cdot 10^{-3}$
X5	Misc./Other Ruptures	F1	$1.05 \cdot 10^{-4}$		100	$2.11 \cdot 10^{-4}$		-100	0	
A7	Rupture of Buried Pipe	F1		$5.00 \cdot 10^{-3}$			$1.01 \cdot 10^{-2}$			$2.49 \cdot 10^{-3}$
A9	Corrosion	F1		$4.09 \cdot 10^{-3}$			$8.28 \cdot 10^{-3}$			$2.04 \cdot 10^{-3}$
A17	Internal Corrosion	F1	$2.85 \cdot 10^{-3}$		100	$5.70 \cdot 10^{-3}$		-50	$1.42 \cdot 10^{-3}$	
A20	External Corrosion	F1	$1.22 \cdot 10^{-3}$		100	$2.45 \cdot 10^{-3}$		-50	$6.12 \cdot 10^{-4}$	
X10	Inadequate Pipe Material	F1	$2.11 \cdot 10^{-6}$		500	$1.27 \cdot 10^{-5}$		-100	0	
X11	Corr. at Girth/Fillet Weld	F1	$2.11 \cdot 10^{-5}$		500	$1.27 \cdot 10^{-4}$		-100	0	
A10	External forces	F1		$1.27 \cdot 10^{-4}$			$2.53 \cdot 10^{-4}$			$6.33 \cdot 10^{-5}$
X19	Earth Movement	F1	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-5}$		-50	$2.11 \cdot 10^{-5}$	
X20	Third Party Damage	F1	$2.11 \cdot 10^{-5}$		100	$4.22 \cdot 10^{-5}$		-50	$1.05 \cdot 10^{-5}$	
X21	Construction Damage	F1	$6.33 \cdot 10^{-5}$		100	$1.27 \cdot 10^{-4}$		-50	$3.16 \cdot 10^{-5}$	

TABLE F.3d

PIPELINE FAULT TREE EVENT SENSITIVITY ANALYSIS (LEAK CASE)

Event Box	Fault Tree Event		Base Input Values	Base Computed Values	% Increase	High Input Values	High Computed Values	% Decrease	Low Input Values	Low Computed Values
A11	Operation Induced Failures	F1		0			0			0
X22	Overpressure	F1	0		100	0		-50	0	
X23	Operator Error	F1	0		100	0		-100	0	
A12	Equipment Failures	F1		$7.83 \cdot 10^{-4}$			$1.57 \cdot 10^{-3}$			$3.90 \cdot 10^{-4}$
X24	Weld Failure	F1	$3.80 \cdot 10^{-4}$		100	$7.59 \cdot 10^{-4}$		-50	$1.90 \cdot 10^{-4}$	
A22	Pipe Failure	F1		$4.03 \cdot 10^{-4}$			$8.14 \cdot 10^{-4}$			$2.00 \cdot 10^{-4}$
X25	Excessive Stresses	F1	$4.01 \cdot 10^{-4}$		100	$8.02 \cdot 10^{-4}$		-50	$2.00 \cdot 10^{-4}$	
X26	Wrong Material	F1	$1.98 \cdot 10^{-6}$		500	$1.19 \cdot 10^{-5}$		-100	0	
A8	Rupture of Surface Equip.	F2		$2.95 \cdot 10^{-4}$			$1.60 \cdot 10^{-3}$			$2.11 \cdot 10^{-5}$
A13	Corrosion	F2		$1.90 \cdot 10^{-4}$			$1.14 \cdot 10^{-3}$			0
X27	Internal Corrosion	F2	$1.33 \cdot 10^{-4}$		500	$7.99 \cdot 10^{-4}$		-100	0	
X28	External Corrosion	F2	$5.72 \cdot 10^{-5}$		500	$3.43 \cdot 10^{-4}$		-100	0	
A14	External forces	F2		$5.92 \cdot 10^{-6}$			$3.55 \cdot 10^{-5}$			0
X29	Construction Damage	F2	$2.96 \cdot 10^{-6}$		500	$1.77 \cdot 10^{-5}$		-100	0	
X30	Third Party Damage	F2	$9.86 \cdot 10^{-7}$		500	$5.92 \cdot 10^{-6}$		-100	0	
X31	Earth Movement	F2	$1.97 \cdot 10^{-6}$		500	$1.18 \cdot 10^{-5}$		-100	0	
A15	Equipment Failure	F2		$9.85 \cdot 10^{-5}$			$4.22 \cdot 10^{-4}$			$2.11 \cdot 10^{-5}$
X32	Failure of an Installation	F2	$1.97 \cdot 10^{-5}$		500	$1.18 \cdot 10^{-4}$		-100	0	
X33	Weld failure	F2	$1.77 \cdot 10^{-5}$		500	$1.06 \cdot 10^{-5}$		-100	0	
A23	Valve/Fitting Failure	F2	$4.22 \cdot 10^{-5}$		100	$8.44 \cdot 10^{-5}$		-50		$2.11 \cdot 10^{-5}$
A24	Pipe Failure	F2		$1.88 \cdot 10^{-5}$			$1.13 \cdot 10^{-4}$			0
X37	Wrong Material	F2	$9.27 \cdot 10^{-8}$		500	$5.56 \cdot 10^{-7}$		-100	0	0
X38	Excessive Stresses	F2	$1.87 \cdot 10^{-5}$		500	$1.12 \cdot 10^{-4}$		-100	0	
A16	Operation Induced Failures	F2		0			0			0
X39	Operator Error	F2	0		500	0		-100	0	
X40	Overpressure	F2	0		500	0		-100	0	

Notes: (1) F1 = Frequency (#/km•year)
F2 = Frequency (#/SE•year)
P = Probability
(2)To quantify event A4, event A8 must be multiplied by 1.07 SE's/km
(3)SE = Surface Equipment USGR = Uncontrolled sour gas (H_2S) release ESD Valve = Emergency Shutdown Valve
(4)Event A3 is computed for Flow Scenario 1 - see Appendix D
(5)NC = Not Computed
(6)Hole Size = Long Rupture, Geometry = Downwind Jet

Reg. for copy
28 May 95

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